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COST ANALYSIS OF TWO AIR QUALITY ATTAINMENT
STRATEGIES

HARBRIDGE HOUSE, INCORPORATED

PREPARED FOR
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**COST ANALYSIS OF TWO AIR QUALITY
ATTAINMENT STRATEGIES**

By

Harbridge House, Inc.
11 Arlington Street
Boston, Massachusetts 02116

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16. ABSTRACT As part of the Commonwealth of Massachusetts' Air Quality Maintenance Planning (AQMP) procedure, this study evaluates the economic costs associated with implementation of two strategies for attainment and short-term maintenance of particulate standards. Both strategies are proposed for application to the City of Worcester. They are as follows: (i) replacement of marginal burners with more energy efficient modern equipment; and (ii) conversion of sources using residual oil to the use of lighter fuels and/or fuels of lower sulfur content. The analysis has included only the economic costs to owners of affected facilities. The study was prepared in order to subsequently coordinate the results with an air pollution control effectiveness analysis to be undertaken separately.		
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EXECUTIVE SUMMARY

In the preparation of its air quality attainment and short-term maintenance plan, the Massachusetts Department of Environmental Quality Engineering (DEQE) is evaluating the feasibility and desirability of implementing two air quality control strategies. Both strategies have been proposed for application to the City of Worcester in order to attain national ambient air quality standards for particulates during the winter months when seasonal loads on combustion sources contribute to violations. The strategies are as follows:

- Replacement of marginal burners with more energy efficient modern equipment.
- Conversion from residual oil to the use of lighter fuels and/or fuels of lower sulfur content.¹

Harbridge House, Inc. is assisting DEQE in the evaluation of these strategies by estimating the economic costs to owners of affected combustion sources that may result from the implementation of one or both measures. This cost analysis, which is summarized below, is to be subsequently coordinated with the results of a strategy air pollution control effectiveness analysis which DEQE is undertaking.

Prior to evaluating the cost associated with each strategy, brief consideration was given to the economic and financial environments in which strategy implementation would occur.

Worcester's Economy and Economic Outlook

- The City of Worcester has undergone an economic reversal during the year from late 1974 to late 1975 as cyclical trends felt nationwide exerted a strong impact on Worcester's durable goods manufacturing sector.

¹ As used by Massachusetts DEQE, residual oil includes #6, #5, and #4 fuel oils.

- Because of the nature of the durable goods sector (the backbone of the Worcester economy), it is expected that recovery will be gradual with some lag behind other areas of Massachusetts and the nation.
- Some economic analysts in Worcester believe that signs of recovery are already apparent, indicating that past levels of productivity may be regained by 1978.

Financing Options

- Depending on the availability and terms, financing options may provide assistance to owners of facilities subject to strategy related costs.
- Private sector facilities are eligible for loans and programs offered by the Small Business Administration (SBA) as well as commercial banking operations. An important criteria for obtaining a loan is the firm's credit worthiness.
- Public facilities, if they cannot fund strategy related expenditures from operating funds, are likely to include the extra costs in a larger bond issue in order to obtain favorable rates and terms.

Marginal Burner Retrofit Strategy

- This strategy proposed replacement of marginal burners, defined in this analysis as natural draft rotary cup burners, with more energy efficient modern equipment. It has a unique advantage over a strategy specifying "add on" pollution control equipment in that a substantial savings may accrue to the owner in the form of reduced fuel bills.
- Costs considered in analysis of this strategy included: equipment costs and installation of the modern burner, interest and depreciation charges on capital expenditures, fuel savings in gallons and fuel price in cents per gallon.
- DEQE specified acceptable equipment for replacement of marginal burners. Manufacturer estimates, based on actual experience in Massachusetts, were used to represent the most likely range of capital and installation costs.

- Private sector financing was conservatively assumed to be obtained at 10 percent interest over five years, while public sector funding was assumed to be obtained at a 5.75 percent rate over a 20-year term.
- Equipment costs were inflated to 1978, as directed by DEQE. A rate of nine percent per year was used based on the historical wholesale price index for heating equipment and a comparison with recently quoted rates in Massachusetts.
- Depreciation was based on the straight line method -- over 25 years -- assuming no scrap value in the 26th year.
- Estimates of fuel savings obtained from manufacturers ranged from ten percent to 25 percent. In consultation with DEQE, a 15 percent annual savings was assumed in the analysis. This figure was based on an estimate that current maintenance practices (unchanged after strategy implementation) include at least one burner adjustment per year. Current fuel oil prices were used, as directed by DEQE.
- Net annual costs or savings during the first year of strategy implementation for all size categories range from a net savings of \$87,500 to a net cost of \$75,900 as shown in Exhibit 1.¹ Costs will be lower (and savings higher) in all subsequent years.
- Net annual costs or savings per site for all size categories range from a savings of \$600 to a cost of \$500 per site.
- Based on the analytical assumptions, public sector facilities on average for all size categories will experience a net savings in the first year ranging from \$28,250 to \$950. Private sector facilities, on average for all size categories, will experience a range of savings/costs from a net savings of \$59,250 to a cost of \$76,900.
- In the public sector, facilities in the 10 through 50 million BTU per hour site size categories will experience net savings in the first year ranging from a total of \$2100 to \$15,100. Net costs

¹ The range reflects the most likely costs of equipment and installation.

EXHIBIT 1
ESTIMATED NET ANNUAL COSTS OR
SAVINGS OR MARGINAL BURDEN
RETROFIT STRATEGY^a

	3 to 6 Million BTU/hour	6 through 10 Million BTU/hour	10 through 25 Million BTU/hour	25 through 50 Million BTU/hour	50 through 100 Million BTU/hour	Total
PAID	\$2800 - (\$400)	(\$4550) - (\$11,250)	\$13,900 - \$2050	\$15,100 - \$10,550	NONE	\$28,350 - \$950
PAID	(\$1300) - (\$16,800)	(\$2800) - (\$38,050)	\$13,400 - (\$34,400)	\$53,700 - \$30,750	(\$3750) - (\$18,400)	\$59,250 - (\$76,900)
TOTAL	\$2500 - (\$17,200)	(\$7350) - (\$49,300)	\$27,300 - (\$32,350)	\$68,800 - \$41,300	(\$3750) - (\$18,400)	\$87,500 - (\$85,950)

^a Figures bracket most likely range. Note: Because of financing assumptions, cost shown represents net annual costs during the first year of implementation. In subsequent years, cost will be lower (or savings higher). () indicates a net cost.

Source: Harbridge House, Inc. 1976. See Exhibit II-4 for more detail on costs and savings.

will be experienced in the first year by facilities in the site size categories from 3 to 10 million BTU per hour, ranging from a total of \$400 to \$11,300.

- In the private sector, net savings are experienced in the first year by facilities in the 25 through 50 million BTU site size category, ranging from a total of \$53,700 to \$30,800. Net costs are experienced in all other categories ranging from a total of \$3000 to \$38,000.
- Evaluation of the time required before capital investment and interest charges are fully recovered in annual fuel bill savings showed that the private sector facilities would require from two to six years, while the public sector would require from 5 to 19 years.
- These burner replacement costs are believed to reflect an overly conservative case largely because of the presence of stand-by units in the Worcester inventory. DEQE has stated that implementation of this strategy will provide a mechanism whereby burners on stand-by boilers may be exempted from the retrofit requirement.

Fuel Type Conversions Strategy

- Although this analysis is addressed as a single strategy, four alternative fuel conversions are actually considered under two assumptions regarding the timing of the implementation of the marginal burner retrofit strategy. The conversions are as follows:
 - Conversion of sources burning #6 (1%S) oil to #6 (0.5%S) oil.
 - Conversion of sources burning #6 oil to #4 oil.
 - Conversion of sources in the under 50 million BTU per hour site size categories burning #6 oil to #2 oil.
 - Conversion of sources in the under 50 million BTU per hour site size categories burning #4 oil to #2 oil. (Sources burning #5 oil are grouped with #4 oil users, as directed by DEQE.)

According to Massachusetts regulations, all sources burning #6 oil are assumed to be burning #6 (1%S) oil.

- Although fuel oil type conversions are often considered as sulfur oxide control strategies, DEQE has considered these conversions for control of particulates in light of recent evidence indicating a positive relationship between particulate emissions and the viscosity and other qualities of fuel burned, such as sulfur content.
- Each of the above conversions is evaluated assuming prior implementation of the marginal burner retrofit strategy and assuming that the strategy has not been implemented. These assumptions were included to provide DEQE with flexibility in the strategy effectiveness evaluation.
- In the conversions from residual (#4 and #6 oils) to distillate (#2 oil) certain modifications of the combustion system are required including replacement of pumps, strainer baskets, and relief valves, and adjustment of the burner. Manufacturer estimates of the costs (based on actual experience in Massachusetts) were used.
- Other cost changes considered included the differential prices of fuel (current prices as directed by DEQE), differences in heat content of different grades of oil, oil preheating requirements, and in conversions from residual to distillate firing, (under the assumption of no prior retrofit of marginal burners) the cost of marginal burner retrofit and resulting fuel savings.
- Interest and depreciation charges were also included as appropriate.
- Because of the coordination with the marginal burner retrofit strategy implementation, it was assumed that conversions would take place in 1978. As directed by DEQE, equipment costs were inflated to that year.
- Results (summarized in Exhibit 2) indicate that the conversion from #4 to #2 oil will be least costly, with total annual costs ranging from \$96,000 to \$172,000 (or \$1200 to \$2200 per site) under both assumptions regarding implementation of the marginal burner retrofit strategy.
 - The 6 through 25 million BTU per hour site size categories were found to incur about 70 percent of total costs in this conversion.

EXHIBIT 2
ESTIMATED TOTAL ANNUAL COSTS OF ALTERNATIVE
FUEL TYPE CONVERSIONS

	#6(1%S) to #6(0.5%S)	#6 to #4	#6 to #2 ^a	#4 to #2 ^a
Assuming Prior Implementation of Marginal Burner Retrofit Strategy	\$413,400	\$792,400	\$419,200 - \$433,700	\$127,700 - \$139,500
Assuming No Prior Implementation of Marginal Burner Retrofit Strategy	\$427,800	\$820,400	\$365,700 - \$436,700	\$ 96,000 - \$171,600

^a Figures bracket most likely range. Because of capital cost financing assumptions, costs shown are for the first five years of implementation and will be lower in subsequent years.

Source: Harbridge House, Inc. 1976. See Exhibits III-6 and III-7 for more detailed breakdowns.

- The conversion from #6 to #4 fuel use was found to be most costly under both assumptions, with total annual costs ranging from \$790,000 to \$820,000 (or \$13,400 to \$13,900 per site).
 - The greater than 100 million BTU per hour site size category was found to incur about 60 percent of total costs in this conversion.
- Total annual conversion costs from #6 (1% S) to #6 (0.5% S) and from #6 to #2 ranged from \$360,000 to \$440,000 (or \$7000 to \$9400 per site) under both assumptions.
 - In the #6 (1% S) to #6 (0.5% S) conversion the greater than 100 million BTU per hour site size category was found to incur 60 percent of the total costs.
 - In the #6 to #2 conversion, the 10 through 50 million BTU per hour site size categories were found to incur about 90 percent of total costs.
- An important result of the #4 to #2 conversion under the assumption of no prior retrofit of the marginal burner retrofit strategy is that fuel costs were found to decrease as a result of strategy implementation. Consequently, after capital costs are fully amortized (five years for private sector facilities and 20 years for public sector facilities), a net savings will be experienced.

I. INTRODUCTION

A. Background and Approach

Pursuant to 40 CFR 51.12(a)-(h), as published in the Federal Register of 18 June 1973, and subsequently revised in 8 May 1974 (39 FR 16343), all states must identify geographic areas which have exceeded or have the potential for exceeding national ambient air quality standards (NAAQS) within the subsequent ten-year period. After these designated areas are reviewed, altered (if deemed necessary), and approved by the Environmental Protection Agency (EPA), each state is required to undertake a thorough analysis of the impact of growth and development on the air quality of the area. Where existing (measured and estimated) ambient levels of a pollutant exceed NAAQS, the plan is to set forth a control strategy for reduction of emission levels to the degree necessary for the attainment and then maintenance of the national standard. Where analysis shows that an area currently complying with NAAQS will not maintain pollutant levels consistent with NAAQS over a ten-year period from the date of plan submittal, a state must develop an effective plan to provide maintenance of air quality standards.

The State of Massachusetts, Department of Environmental Quality Engineering (DEQE) is in the process of preparing its air quality attainment and short-term maintenance plan for submission to Region I, EPA. The City of Worcester has been identified by DEQE as exceeding the particulate standards during the winter months. Moreover, the agency has concluded that seasonal loads placed on combustion sources are one component of the particulate problem.

In order to attain particulate standards year round in Worcester, the following two strategies are being considered by DEQE for inclusion in their 15 May plan submission.

- Replacement of inefficient marginal burners with more energy-efficient modern equipment.
- Conversion of sources using residual fuel oil to lower sulfur content or lighter fuel oil.¹

¹As used by Massachusetts DEQE, residual oil includes #6, #5, and #4 fuel oils, while distillate oil refers to #2 fuel oil.

In assessing the feasibility and desirability of implementing these strategies, a cost effectiveness evaluation has been undertaken jointly by Harbridge House and DEQE. DEQE is evaluating the particulate emission reductions associated with implementation, while Harbridge House has analyzed the economic implications. This report details the methodology and results of the Harbridge House effort.

Approaches taken in evaluation of the two strategies differ considerably. On the one hand, the marginal burner retrofit strategy assessment was aimed at determining not only the economic costs of burner replacement, but also the annual operating cost savings resulting from the use of more energy-efficient modern equipment. These two aspects of the analysis have then been integrated to determine the time period over which the costs will be recovered. On the other hand, the fuel type conversion strategy, represents a cost to owners without any significant economic advantages. Consequently, this latter analysis focuses solely on incremental fuel-related expenses and associated capital costs.

Evaluation of the two strategies is similar, however, in that only economic costs to owners of affected facilities (as opposed to the general public) are evaluated. Moreover, for both strategies, costs have been aggregated by site (or facility) size categories in order to reflect various alternative applications of the strategies.

It is important to recognize that the analysis undertaken by Harbridge House has not been aimed at assessing the financial impact on particular companies of the costs associated with implementation of the strategies. Clearly, the costs will differentially affect owners of facilities which are subject to burner replacement and/or fuel oil type conversions. Several factors are likely to influence the relative severity of impact experienced, including industry structure, current, and near-term economic conditions, and the availability and terms of financing options. In order to provide some insight into the economic and financial environments in which the proposed strategies would be implemented, the following two sections of this chapter briefly describe salient aspects of the Worcester area economy and the types of financing arrangements potentially available to owners of affected facilities.

B. The Worcester Area Economy and Economic Outlook¹

Worcester today is the industrial and commercial center of central Massachusetts. In 1974 there were 3,797 firms reporting to the State Division of Employment Security (DES). These firms employed 82,701 personnel in 1974 with annual payrolls totalling \$741 million.

The manufacturing sector of the Worcester economy was based historically on four major industries: wire manufacture (specializing in piano wire), the textile industry, grinding wheel production, and envelope production. Today, the major manufacturing groups in Worcester, in order of their workforce size, are: fabricated metal products; machinery (excluding electrical); stone, clay and glass products; primary metal products; printing and publishing; food and kindred products; and leather and leather products. These firms employed 31,165 persons in 1974 which amounted to 79 percent of the total manufacturing workforce in that year.

The retail and wholesale trade section of the economy showed 285 wholesale firms in 1974 employing 5,794 persons and 1,028 retail firms with 12,807 persons for that same year. The number of retail trade firms in 1974 was 50 percent fewer than those recorded in 1972.

During the past year and a half, dramatic changes have occurred in the economic vitality of the Worcester area. In December 1974, for example, the Worcester Labor Market Area had the second lowest unemployment rate in the State. Unemployment averaged below the state-wide average and was equal to the national rate of 7.2 percent. One year later, in December 1975, unemployment had risen to 11.6 percent and was surpassed by only one other area of the State. Moreover, a high of 14.4 percent unemployment had been experienced in the intervening period (June 1975).

¹ The information described here is based upon discussions with state, regional, and local economic analysts and planners and upon published sources including: "Massachusetts Profile of Worcester," Massachusetts Department of Commerce and Development, March 1976; Annual Manpower Planning Report for the Worcester SMSA. Massachusetts Division of Employment Security. January 1975; "Area Manpower Review for the Worcester Labor Market Area." Massachusetts Division of Employment Security. Winter, 1976; "Manpower Requirements for the SMSA by Occupation and Industry, 1970-1980," Massachusetts Division of Employment Security, October, 1975.

In addition, over the year from December 1974 to December 1975, non-farm employment decreased by 3100 persons. This was primarily attributable to a slump in the durable goods manufacturing sector, which has been hard hit by reduced capital goods orders. Employment in the consumer goods sector, however, has remained firm over the year with some increases in textile and leather manufacturing. Both government employment and employment in the service sector increased slightly, while all other sectors of non-manufacturing declined except contract construction which remained the same over that year.

A significant aspect of this recent downturn in the Worcester economy is its timing with regard to recessionary trends in the nation and in Massachusetts, as a whole. The New England states traditionally lag behind the nation in experiencing swings in economic conditions. Moreover, the impact of nationwide trends is usually more severe in New England as opposed to the rest of the country. The Worcester area, in addition to lagging behind the nation, also has been found to experience cyclical trends apparent in other parts of New England later than the rest of Massachusetts. Economic analysts attribute this lag to Worcester's strong durable goods manufacturing base, because orders for investment type goods are placed months and years in advance of delivery. This "protective shield" against short-term swings in the national economy, works to Worcester's disadvantage, however, when recessionary economic forces persist and backlogged orders become depleted.

Apparently, this phenomenon has begun to be felt in Worcester, with the result that recovery is likely to be more gradual than in other areas. Other sectors nationwide will have to recover sufficiently before momentum is built up in the capital goods market for Worcester's durable manufacturers to regain past levels of productivity.

Nevertheless, there is a feeling among economic analysts that the region is beginning to show signs of coming out of the current recession and that the remainder of 1976 will show improvements in the area's economy.¹

¹ Manpower Requirements for the SMSA by Occupation and Industry 1970-1980, Massachusetts Division of Employment Security. October 1975.

Recent forecasts of commercial and industrial activity in Worcester over the next three to five years are not available. However, if the posture of economic analysts is correct and a reversal has started to take place, it appears likely that full recovery will occur within the time frame of this study.

C. Financing Options

Financing capital expenditures allows the owners of facilities affected by costs from strategy implementation to spread the costs out over several years. This, in turn, has the effect of freeing other monies to carry on operations. In this manner, the availability and terms of financing options can be viewed as a force mitigating the potential impact of actions which increase capital requirements. There is, however, at least one caveat to this optimistic view of the role of financing as a mitigating factor. In particular, facilities which are currently operating close to the margin of financial feasibility may be unable or unwilling to take on a medium to long-term financial commitment. Their need for capital may be most pressing in areas unrelated to strategy implementation, such that if they can obtain capital expenditure financing, combustion system modification would likely be a low-priority for its use.

In order to provide a basis for further exploration of the potential role of financing options in providing assistance to owners subject to strategy related costs, a brief summary of alternative arrangements open to private and public sector facilities is discussed below.

1. Financing for Private Industry

There currently exist several financing options for private firms facing capital expenditures from strategy implementation. The most direct case would be a firm financing these costs out of their operating capital. However, in the case of firms unable to meet these estimated expenses out of their operating capital, loan programs do exist which can aid the businessman in meeting these added costs.

a. Small Business Administration Air Pollution Control Program

The SBA provides support and in some cases direct loans to small businesses to help meet federally mandated air quality regulations. Under

their Air Pollution Control (APC) Program, the SBA may guarantee 90 percent of a bank loan which currently is offered at a maximum interest of 10-1/2 percent annually over a period of ten years.¹ Interest rates could be obtained below that maximum according to the individual credit worthiness of the prospective firm applying to a bank.

If bank financing were not available to a firm, a direct SBA loan could be obtained. The individual firm would have to first submit its plans for equipment purchase or modification to DEQE for their approval prior to granting of the loan. The present interest rate on these direct SBA loans is 6-5/8 percent annually over ten years.²

b. Private Financing

Also available to a firm is conventional bank financing based upon current market conditions and the credit worthiness of the prospective firm. Interest rates and terms would be set by the bank at the time of application. However, it should be pointed out that a firm unable to meet the relatively small capital expenditures required by the strategies (estimated to average below \$15,000) from its operating capital would not receive the most favorable terms from a bank. Typically, such conventional loans, are made for much larger amounts.

2. Financing for the Public Sector

In the case of a public facility such as a school, the source of funds would be the municipal budget as financed by municipal bonds. The City of Worcester would include these added costs in their overall municipal budget for the year(s) in which these replacements were to be made. Rather than request funds separately for these

¹ Daniel Rich, Loan Officer, Small Business Administration, Boston District Officer. Telephone interview 16 April, 1976.

² Ibid.

relatively minor costs, the City would most likely include the costs in a larger bonding issue (or if feasible, fund them out of general operating funds). By including relatively small costs in its overall municipal funding program, the City would be able to take advantage of a reduced bonding interest rate. Currently, the City of Worcester rate for municipal bonds is around 5-3/4 percent for a twenty-year term.¹

D. Organization of the Report

In Chapter I the two air quality control strategies proposed for application in the City of Worcester have been briefly introduced. Background information regarding the Worcester economy and economic outlook has been presented to provide some insight into the environment in which the economic costs, evaluated in subsequent Chapters, will be incurred. Attention, furthermore, has focused on options which may provide assistance in financing costs associated with strategy implementation.

Following this presentation, Chapters II and III define each of the strategies, summarize the methodologies used in the cost evaluations, and describe the results. Chapter II addresses the marginal burner retrofit strategy while Chapter III deals with alternative fuel type conversions. One appendix, included at the end of the report, summarizes the experience of the State of Maryland in implementing a rotary cup burner retrofit regulation.

¹Barry Cluff, Municipal Bond Department, First National Bank of Boston. Telephone interview 16 April, 1976. (As of 1 June 1976 market changes have resulted in a rate increase to somewhere over 6 percent. Ibid.)

II. MARGINAL BURNER RETROFIT STRATEGY

A. Background and Approach

The Massachusetts DEQE has proposed an air quality control strategy for particulates which focuses on replacing marginal burners in combustion systems of all sizes within the Worcester City limits. A strategy requiring replacement of marginal burners has a distinct advantage over a control method utilizing add-on pollution control equipment in that substantial efficiencies in fuel use are likely to be achieved by burner replacement. Consequently, the benefits of implementation of such a retrofit strategy are not limited to pollution control effectiveness, but also must include fuel cost savings to owners of affected facilities.

In order to assess the impact of this strategy, marginal burners have been defined by DEQE as natural draft rotary cup burners. The rationale for this definition is based on the performance characteristics of these burners, which are briefly described below.

1. Natural Draft Rotary Cup Burner Characteristics¹

The rotary cup burner is designed to throw air off the edge of a rotating cup into a fast-moving air stream. The oil tends to bleed off the cup in sheets or strings which are then broken into droplets as the oil is accelerated into the air stream. Inefficient combustion results from the reliance of natural draft rotary cup burners on the natural draft of the fire to suck the major portion of the air into the combustion chamber. In most cases, this means there is insufficient energy intensity brought to bear on the oil-and-air environment to cause rapid breakup of the oil into very small particles. Such atomization is necessary for effective combustion and emission control. Moreover, since there is so little control over the quantity of air introduced into the combustion chamber, substantial energy loss often results as heated air, unburned oil, and carbon is emitted through the stack.

¹ This discussion is based on Background Information for Proposed Changes in Maryland Regulations, Maryland State Department of Health and Mental Hygiene, April 1974.

In addition, the degree of atomization of the oil thrown off the rotary cup is dependent on how well the oil can be expanded in streams which, in turn, is dependent on the viscosity and the surface tension of the oil. As a result, distillate oil which has a lower viscosity than residual oil (at the same temperature) does not burn well in natural draft rotary cups. Instead of being strung out and broken into very small particles, the distillate oil tends to move across the air stream in fairly large droplets. When this happens, the distillate oil may cross the stream and deposit on the outer wall for inefficient surface combustion.

Despite these characteristics of inefficient combustion, natural draft rotary cup burners were installed widely in smaller (generally under 15 million BTU per hour furnace heat input) combustion systems until about 10 or 15 years ago. Since then, new installations have been declining, but hundreds of old systems still remain in operation. The choice of natural draft rotary cups in past years can be largely attributed to their relatively low capital cost, their reliability, and their relatively simple maintenance requirements. Moreover, during times when oil price and availability were not significant constraints, more efficient fuel use and resulting savings in annual operating costs apparently did not provide effective arguments in favor of a higher capital cost burner.

2. Types of Costs Considered

The major cost to current site owners where natural draft rotary cup burners are used will be the capital cost for purchase and installation of the new burner equipment. These capital costs will vary by the size of the burner unit being installed and by the installation characteristics associated with each unit at a specific site.

The DEQE provided Harbridge House with specifications of acceptable burner equipment for replacement of marginal units. Air atomizing burners and primary modulating rotary cup burners were considered the most likely candidates for replacement, although consideration was also given to steam atomizing units.

The steam atomizer burners have not been considered in subsequent analysis because the Worcester inventory did not provide sufficient detail to determine those facilities that could accommodate the constraints associated with that type of equipment. In particular, the steam atomizer requires a high pressure system, a full-time attendant to monitor operation, a source of steam, and some very sophisticated control equipment which results in costs ranging from \$30,000 to over \$100,000 for a single unit.

In addition to the above burner types, DEQE specified that replacement equipment include modulating firing controls. Monitoring and smoke sensing devices, however, were not considered as part of the replacement equipment. (These are required under another regulation.)

Initial discussions with DEQE indicated that at least ten percent of the units subject to burner replacement should be assumed to require boiler modification or replacement because of their age. Subsequent discussions with manufacturers, however, indicated that the costs of boiler modification and the need for boiler replacement are very specific to the age and type of boiler and the configuration of the combustion system layout. Moreover, there is such wide variation in the costs of boiler modification or replacement (because of the above-cited factors) that manufacturers would not venture to estimate even "ball park" figures. Because time and data limitations did not permit development of more detailed cost estimates in this analysis, it has been assumed that existing boiler characteristics will not pose costly constraints on burner installation.

Consideration was also given to the need for increasing the load carrying capabilities of plant electrical systems as a result of burner replacement. (The replacement equipment has higher electrical needs per unit.) Manufacturers noted, however, that the replacement units would likely have a smaller capacity than the original marginal burner. This would result in a lower equipment cost than indicated by a cost figure estimated on the basis of original burner capacity and would also probably result in no net change in electrical requirements. As a result of this information, two additional assumptions were made. First, it was assumed that

the capital costs of replacement burners would be a function of the capacity of the old (marginal) burner since data did not permit estimates of the extent or degree of capacity reductions that would be likely to occur. Secondly, it was assumed that the electrical requirements (and therefore costs) would not change as a result of burner replacement.

Based upon discussions with DEQE, it was further assumed that no change in maintenance practices or other (non-fuel) operating costs would result from this burner retrofit strategy.

A second cost considered in this analysis is for financing. Since capital, itself, has a cost -- either an opportunity cost or a financing cost -- several assumptions regarding the provision of capital were made (see Section B). Moreover, different assumptions were made in evaluating the cost of capital to private concerns as opposed to public sector facilities. The wide variations which can occur in the financing opportunities within each of these two categories (public and private) were not addressed in the quantitative analysis; however, a generalized discussion of financing options is included in Chapter I.

Costs associated with depreciation of capital equipment were also assumed to be incurred, based upon the consideration that owners put aside enough capital each year to replace the equipment at the end of its useful life. It is recognized, however, that depreciation of equipment can provide significant tax advantages to owners. Under such circumstances (not quantitatively addressed in this study) depreciation may represent a net benefit of new equipment purchases.

A final significant cost item -- in this instance a cost savings -- was the annual fuel cost savings resulting from the greater operational efficiency of the new burners. Based upon discussions with burner manufacturing and service representatives and with DEQE staff, it was determined that a reasonable (and conservative) estimate of fuel conservation would be 15 percent of total current fuel usage.

3. Worcester Marginal Burner Inventory

The Worcester Inventory of combustion sources provided the data base for specification of the characteristics of sites subject to the marginal retrofit strategy.

The inventory data shows for each site: the number and type of burners; the type of boiler and burner controls; the rated capacity in million BTU per hour and in gallons per hour; and the fuel use and type. Because of the anticipated implementation of the proposed strategies on the basis of the total rated capacities of all combustion units at a site, manipulation of data in the marginal burner inventory retained the following site-size categories: 3 to 6 million BTU's per hour; 6 through 10 million BTU's per hour; 10 through 25 million BTU's per hour; 25 through 50 million BTU's per hour; and 50 through 100 million BTU's per hour. Despite this aggregation in the presentation of results, certain costs, notably the capital costs of replacement equipment, were found to be a function of individual unit capacity (rather than total site capacity) and were accordingly evaluated on a burner-by-burner basis.

A summary of the Worcester rotary cup burner inventory by site, capacity, and fuel type is shown in Exhibit II-1.

For the facilities fitted with rotary cups, private ownership is the most prevalent. There are 108 private sites identified (roughly 72 percent) which currently use about 10,400 gallons of all fuel oils (roughly 81 percent) in the Worcester marginal burner inventory. This is compared with 41 public facilities using slightly over 2300 gallons of all fuel oils. Usage by type shows that half of the total sites, or 72 out of 149 locations, use #4 oil.¹ Of the total sites, 28 percent use #6 oil and 22 percent use #2.

Significantly, the users of #6 oil account for almost half of the total fuel volume of all types used; #4 oil was the next most used, while #2 accounted for 13 percent of total fuel usage. The average yearly burner fuel consumption with #6 oil was 68,000 gallons for both public and private facilities compared with about 41,000 gallons of #4 oil and almost 30,000 gallons of #2 oil. Notably, most of the public facilities on the inventory use either #4 or #2 oil.

¹ As directed by DEQE, users of #5 fuel oil have been grouped with the #4 fuel oil users.

EXHIBIT II-1

SUMMARY OF WORCESTER MARGINAL BURNER INVENTORY

Site Size Categories	No. 6 Fuel Type Used			No. 4 Fuel Type Used		
	Number of Sites	Number of Marginal Burners	Marginal Burner Fuel Use (1000 Gallons)	Number of Sites	Number of Marginal Burners	Marginal Burner Fuel Use (1000 Gallons)
3 to 6 Million BTU/hour						
-- Public	0	0	0	8	10	249.6
-- Private	3	3	130.4	9	9	406.0
-- Total (% of all size categories)	3 (7%)	3 (4%)	130.4 (2%)	17 (24%)	19 (16%)	655.6 (13%)
6 through 10 Million BTU/hour						
-- Public	0	0	0	11	21	302.3
-- Private	9	13	547.2	19	28	1449.1
-- Total (% of all size categories)	9 (21%)	13 (15%)	547.2 (9%)	30 (42%)	49 (41%)	1751.4 (36%)
10 through 25 Million BTU/hour						
-- Public	1	3	250.0	9	18	750.0
-- Private	18	32	1806.8	12	24	1160.5
-- Total (% of all size categories)	19 (44%)	35 (39%)	2056.8 (34%)	21 (29%)	42 (35%)	1910.5 (39%)
25 through 50 Million BTU/hour						
-- Public	1	2	104.1	3	7	421.0
-- Private	7	21	2287.8	1	2	182.7
-- Total (% of all size categories)	8 (19%)	23 (25%)	2391.9 (39%)	4 (5%)	9 (8%)	603.7 (12%)
50 through 100 Million BTU/hour						
-- Public	0	0	0	0	0	0
-- Private	4	15	965.5	0	0	0
-- Total (% of all size categories)	4 (9%)	15 (17%)	965.5 (16%)	0	0	0
TOTAL ALL CATEGORIES						
-- PUBLIC	2 (5%)	5 (6%)	354.1 (6%)	31 (43%)	56 (47%)	1722.9 (35%)
-- PRIVATE	41 (95%)	84 (94%)	5737.7 (94%)	41 (57%)	63 (53%)	3198.3 (65%)
-- TOTALS (%)	43 (100%)	89 (100%)	6091.8 (100%)	72 (100%)	119 (100%)	4921.2 (100%)

Source: Harbridge House, Inc. (1976).

Type Used			No. 2 Fuel Type Used				All Types of Fuel Used			
Marginal Burners	Marginal Burner Fuel Use (1000 Gallons)		Number of Sites	Number of Marginal Burners		Marginal Burner Fuel Use (1000 Gallons)	Total Number of Sites	Total Number of Marginal Burners		Total Marginal Burner Fuel Use (1000 Gallons)
(16%)	249.6		4	5		120.1	12	15		369.7
	406.0		15	16		458.4	27	28		994.8
	655.6	(13%)	19 (55%)	21 (34%)		578.5 (33%)	39 (26%)	43 (16%)		1364.5 (11)
(41%)	302.3		1	2		40.0	12	23		342.3
	1449.1		7	13		329.2	35	54		2325.5
	1751.4	(36%)	8 (24%)	15 (24%)		369.2 (21%)	47 (31%)	77 (28%)		2667.8 (21)
(35%)	750.0		3	15		129.5	13	36		1129.5
	1160.5		3	7		288.4	33	63		3255.7
	1910.5	(39%)	6 (18%)	22 (35%)		417.9 (23%)	46 (31%)	99 (37%)		4385.2 (34)
(8%)	421.0		0	0		0	4	9		525.1
	182.7		1	4		409.5	9	27		2880.0
	603.7	(12%)	1 (3%)	4 (7%)		409.5 (23%)	13 (9%)	36 (13%)		3405.1 (27)
	0		0	0		0	0	0		0
	0		0	0		0	4	15		965.5
	0		0	0		0	4 (3%)	15 (6%)		965.5 (7)
(47%)	1722.9	(35%)	8 (24%)	22 (36%)		289.6 (16%)	41 (28%)	83 (31%)		2366.6 (18)
(53%)	3198.3	(65%)	26 (76%)	40 (64%)		1485.5 (84%)	108 (72%)	187 (69%)		10,421.5 (82)
(100%)	4921.2	(100%)	34 (100%)	62 (100%)		1775.1 (100%)	149 (100%)	270 (100%)		12,788.1 (100)

Among burners using #6 oil, most were in the 6 through 50 million BTU per hour size categories. Of the burners using #6 oil, 95 percent were privately owned facilities, with public sites found only in the two size categories from 10 through 50 million BTU's per hour. Burners using #4 oil occur in all but the largest size category, 50 through 100 million BTU's per hour. These burners are almost equally divided between private and public ownership with most burners in the size range from 3 million through 50 million BTU's per hour. While the greatest number of sites and burners use #4 oil, only 38 percent of the total oil consumed is #4. For #2 oil usage, the ratio of public to private facilities is 35 percent public, with the smallest size categories having the greatest usage. As with the #4 oil usage, there are no facilities using #2 oil in the 50 through 100 million BTU category. Of note in usage of #2 oil is that for the largest size category, 25 through 50 million BTU's per hour, private facilities with 6 percent of the total number of burners for all #2 usage consumed over 23 percent of the total #2 oil.

As a final note, it must be pointed out that the Worcester inventory of oil burner types, used as the basis for this analysis, does not specify the type of rotary cup burners in use so that it was not possible to distinguish (marginal) natural draft rotary cups from primary modulating rotary cups (which are acceptable). Moreover, it was not possible to segregate those burners on stand-by boilers from those on boilers in regular use. (DEQE anticipates that implementation of the strategy will provide a mechanism whereby exemptions to the retrofit requirement may be provided for stand-by units.) From discussions with DEQE staff, it was determined that the likelihood of a substantial number of these sites having the newer rotary cup burner types was small and would, therefore, not significantly affect the analysis. As discussed in subsequent sections, however, the presence of stand-by units (which may not have to be replaced) may have resulted in considerable overestimation of replacement costs.

B. Costing Procedures

The magnitude of costs assumed for replacement equipment as well as the costs of capital and depreciation are described below with respect to sources of information and specific assumptions used in subsequent analysis. It should be noted that in this analysis, it has been assumed that all replacements are initiated and completed in 1978 based on DEQE's estimate of the earliest feasible year for requiring retrofit completion.

1. Marginal Burner Replacement Costs

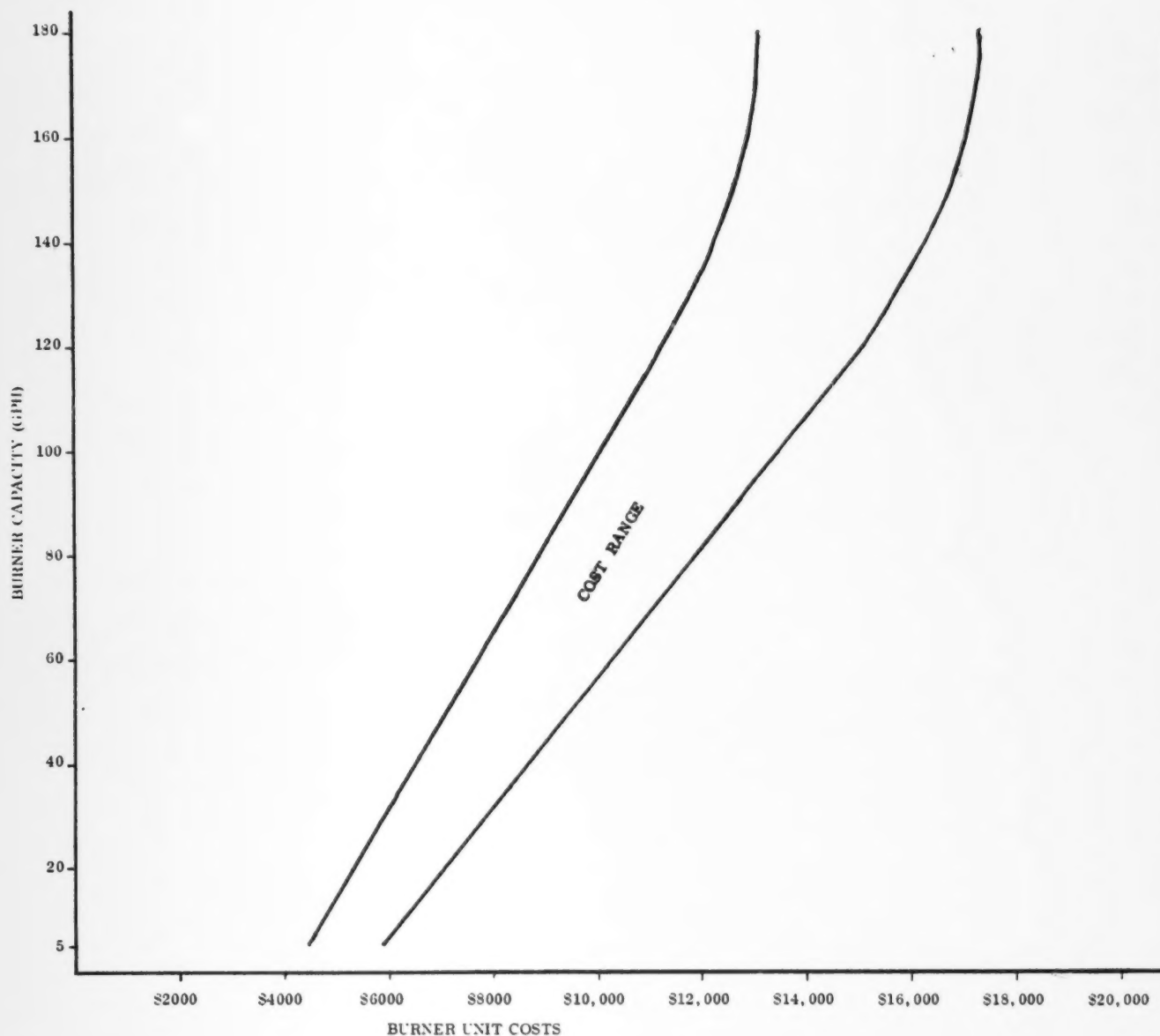
The costs estimated for burner replacement are based upon burner capacity ranges. Exhibit II-2 shows the breakdown of burner capacities in gallons per hour (GPH) and 1978 dollar costs for each size. Capacities taken from the inventory range from about 5 GPH to a high of 180 GPH with costs estimated in the range from \$3700 to \$16,600. These low-high estimates were determined through interviews with manufacturers to be representative of replacement cost in Massachusetts. These equipment costs are further assumed to be relatively competitive between the two major burner types being considered here: primary modulating rotary cup burners and air atomizing burners.

At the request of DEQE, the costs were inflated at a rate of 9 percent per year based on the average annual rate of wholesale price increases from 1969 to 1975 for heating equipment plus two percent to account for future contingencies.¹ The nine percent figure was considered reasonable in light of some recent electric utility construction price adjustment clauses (in Massachusetts) obtained from DEQE, that were based on rates in the vicinity of 10 percent per year.

¹ Percentage increase in wholesale prices for heating equipment as follows: 1969 to 1970, 4.9%; 1970 to 1971, 4.4%; 1971 to 1972, 2.3%; 1972 to 1973, 19.0%; 1973 to 1974, 5.9%; 1974 to 1975, 21.7%. Source: U.S. Department of Commerce Bureau of Census Statistical Abstract of the United States (1975).

EXHIBIT II-2

ESTIMATED COST OF OIL BURNER EQUIPMENT TO
TO REPLACE THE MARGINAL BURNERS OF VARIOUS SIZES



Source: Harbridge House, Inc. 1976.

For the capital costs shown in Exhibit II-2, manufacturers estimated that about 25 percent of the total costs would be required for installation with the remainder representing equipment costs. Some slight installation cost savings would be experienced when replacing two or more burners at the same site. These economies have not been included here, however, because of their relative insignificance with regard to total costs.

In addition, because of the Maryland experience with a rotary cup burner retrofit regulation (see Appendix A), manufacturers were questioned about the fuel capabilities of replacement burners. For the types of burners specified above, manufacturers indicated that no increased cost would be incurred in order to accommodate multiple fuel firing capabilities.

2. Increased Efficiency in Fuel Use

Discussions with industry representatives indicated that fuel use efficiencies resulting from replacement of marginal burners with modern equipment have averaged from 10 to 20 percent, with a substantial portion of facilities obtaining efficiencies as high as 25 percent. Clearly the degree of efficiency resulting from replacement is a function of both the condition of the marginal burner and the maintenance applied to the new unit. Consequently, the figure of 15 percent fuel savings which has been utilized in subsequent analysis, was determined in consultation with DEQE regarding the Worcester inventory and the typical maintenance practices of owners.¹ The 15 percent figure is based on the assumption that normal maintenance includes one burner adjustment per year. (As previously noted, the cost of this burner adjustment -- \$75 to \$100 -- has not been considered as an incremental cost resulting from strategy implementation.)

In costing out the fuel savings, current fuel prices were assumed as directed by DEQE. As described in Chapter III, the 1976 average prices for #6 oil, #4 oil, and #2 oil are: \$0.28; \$0.29; and \$0.32, respectively. By assuming current prices, however, it should be noted that the value of future fuel bill savings is probably understated.

¹ For added flexibility, results are also shown for 10 percent and 5 percent fuel savings in Exhibits II-3 and II-4.

3. Cost of Capital

As discussed earlier, costs of capital -- either opportunity costs or financing costs -- will vary according to several separate criteria for the private and public sectors, respectively.

a. Private Sector

Guidelines of the federal Office of Management and Budget¹ call for an annual interest rate of 10 percent to be applied in evaluating the benefits of and costs of programs or projects of a type such as those being considered here. Further discussions with area bankers and federal loan program officials to determine current generalized interest rates and financing procedures found varying rates and financing periods which might be applied. Bankers interviewed offered their opinions based upon typical and generalized situations which correspond to the likely cases involved in this analysis. For example, a bank in Worcester which offers commercial loans to finance pollution control expenditures proposed an interest rate of 6-3/4 percent available for five or seven years; the SBA program discussed previously currently has a rate of 6-5/8 percent for ten years; while a commercial bank in Boston stated a rate of 10-3/4 percent over three years. Clearly, the range of financing opportunities will vary according to the credit situation of an individual firm. The lower interest rates and more favorable financing terms described reflect a firm with sound financial base and credit, while the higher rates would apply to less sound businesses.

Based upon the financing information obtained, and after discussions with Massachusetts DEQE, an annual interest rate of 10 percent over a period of five years was used. This financing rate reflects a conservative estimate of the conditions which are likely to exist for firms needing to secure commercial financing.

b. Public Sector

For public financing of these burner replacements, similar calculations were made. The only variation was in the financing applied to the capital. Based

¹ Executive Office of the President, Office of Management and Budget, Circular No.A-94, Revised, 27 March 1972: Washington, D. C.

upon discussions with bankers and the City Treasurer's office in Worcester, it was determined that current bank interest rates for the City's general obligation bonds was about 5-3/4 percent for a twenty-year issue. For the purposes of this analysis, we assumed this 5.750 rate over a twenty-year term.

Under this procedure, the annual financing payment for year one of the bond period (as well as subsequent years) were calculated according to current public sector financing methods. (The total payment for interest and principal would be large initially, and then decrease over time.) The amount of the total bond issue would most likely be larger than simply the cost of retrofitting burners in public facilities since it would include all public financing projects for an annual or bi-annual period. However, for purposes of this analysis, we assume the total public financing costs to reflect only the capital costs involved in burner replacement.

4. Depreciation

Depreciation of the capital cost of equipment was based upon the normal life expectancy of such equipment from discussions with industry representatives. Yearly depreciation was assumed as a straight-line value carried out over twenty-five years. This yearly figure was combined with the yearly capital financing costs to both the public and private sectors to determine an annual cost to the users. At the end of its useful life, no scrap value has been attributed to the equipment.

C. Analysis and Results

Harbridge House has utilized two approaches in assessing the costs and savings resulting from replacement of marginal burners with acceptable burners of improved efficiency. The first approach derives a payback period for the private and public sectors based upon the range of total capital costs, including costs for financing, divided by the annual fuel cost savings occasioned by improved burner efficiency. This payback time serves as a vehicle for comparison of alternative investment costs and fuel cost savings in the various size categories. In the second approach, the

incremental annual expenditures (including principal, interest, and depreciation) and fuel cost savings resulting from strategy implementation were assessed. This method has the advantage of providing an estimate of the net annual savings or costs attributable to burner replacement. Exhibits II-3 and II-4, respectively, illustrate the method and results of these two analyses.

In Exhibit II-3, the payback period in years is shown for the public sector, private sector, and their combined payback by site-size category. The total capital costs include ranges of principal and interest payments based upon the assumptions discussed in Section B. The fuel cost savings are constant yearly returns which are based upon the improved efficiency of the replacement burner operation.¹ Where the fuel savings return is high relative to capital costs, the payback period is short, while higher relative capital costs and lower fuel cost savings extend the payback time.

As indicated in Exhibit II-3, the payback period ranges from two to six years in the private sector and from five to 19 years in the public sector. Within the private sector, the shortest payback periods occur in the 10 through 25 and 25 through 50 million BTU's per hour categories, in which from three to five years and two to three years, respectively, is required for fuel cost savings to outweigh total costs of capital and interest. In both of these size groups, costs are recovered prior to the final payment for financing which occurs in year five. In the other private sector size categories, the payback occurs in the fourth and fifth years.

As shown in Exhibit II-3, the payback periods in the public sector are generally longer than in the private sector. This is a direct reflection of the data base, because the different financing arrangement assumed for public sector facilities should tend to cause the payback periods to be shorter. In most cases, the payback period occurs within ten years for the public facilities, however, for the 6 through 10 million BTU per hour size category, payback extends to the 14th through 18th years.

¹ Fuel cost savings are shown for increased efficiencies of 15 percent, 10 percent, and 5 percent. As previously noted the figure of 15 percent has been assumed in this analysis.

EXHIBIT II-3
ESTIMATED YEARS UNTIL RECOVERY OF EXPENDITURES FOR
MARGINAL BURNER REPLACEMENT

	Total Capital Cost and Interest ^A (Low -- High)	Annual Fuel Cost Savings ^B		Numbers of Years Until Payback ^C
		At 15%	At 10%	
3 to 6 Million BTU/hour				
--Public	\$ 141,000 -- \$ 186,700	\$ 16,700	\$ 11,100	8.4 -- 11.2
--Private	\$ 201,000 -- \$ 268,100	\$ 45,200	\$ 30,100	4.4 -- 5.9
--Total	\$ 342,000 -- \$ 454,800	\$ 61,900	\$ 41,200	5.5 -- 7.3
6 through 10 Million BTU/hour				
--Public	\$ 215,400 -- \$ 287,700	\$ 15,200	\$ 10,100	14.2 -- 18.9
--Private	\$ 454,400 -- \$ 606,700	\$102,300	\$ 68,200	4.4 -- 5.9
--Total	\$ 669,800 -- \$ 894,400	\$117,500	\$ 78,300	5.7 -- 7.6
10 through 25 Million BTU/hour				
--Public	\$ 388,700 -- \$ 517,400	\$ 49,600	\$ 33,100	7.8 -- 10.4
--Private	\$ 620,300 -- \$ 826,800	\$156,900	\$101,600	3.8 -- 5.3
--Total	\$1,009,000 -- \$1,344,200	\$206,500	\$137,700	4.9 -- 6.5
25 through 50 Million BTU/hour				
--Public	\$ 151,600 -- \$ 201,300	\$ 29,100	\$ 19,400	5.2 -- 6.9
--Private	\$ 298,000 -- \$ 397,200	\$122,600	\$ 81,700	2.4 -- 3.2
--Total	\$ 449,600 -- \$ 598,500	\$151,700	\$101,100	3.0 -- 3.9
50 through 100 Million BTU/hour				
--Public	\$ 0	0	0	---
--Private	\$ 189,500 -- \$ 252,800	\$ 40,100	\$ 26,700	4.7 -- 6.3
--Total	\$ 189,500 -- \$ 252,800	\$ 40,100	\$ 26,700	4.7 -- 6.3
All Size Categories				
--Public	\$ 896,700 -- \$1,193,100	\$110,600	\$ 73,600	8.1 -- 10.8
--Private	\$1,763,200 -- \$2,351,600	\$467,100	\$311,400	3.8 -- 5.0
--Total	\$2,659,900 -- \$3,544,700	\$577,700	\$385,000	4.6 -- 6.1

A Figures (in 1978\$) bracket range of likely costs.

B Figures based on 1976 prices and therefore represent minimum potential savings. The 15% savings have been assumed in the analysis.

C Calculated by dividing cost by annual savings. (Based on 15% savings in fuel use.)

Source: Harbridge House, Inc. 1976.

EXHIBIT H-4

INVESTMENT SAVINGS ESTIMATE FOR THE PUBLIC AND
PRIVATE SECTORS

	3 to 6 Million BTU/Hour		6 through 19 Million BTU/Hour		10 through 25 Million BTU/Hour	
PRIVATE SECTOR						
<u>Savings</u>						
● Annual Fuel Savings	\$ 45,200		\$ 102,350		\$ 156,900	
<u>Costs</u>						
	Low	High	Low	High	Low	High
● Capital Costs (1978\$)	\$ 157,650	\$ 210,300	\$ 356,450	\$ 475,850	\$ 426,550	\$ 648,450
● Financing (capital cost @ 10% over five years)	40,200	53,600	90,900	121,350	124,050	165,350
● Depreciation (capital costs over 25 years)	6,300	8,400	14,250	19,050	19,450	25,950
● Total Annual Costs	\$ 46,500 \$ 62,000		\$ 105,150 \$ 140,400		\$ 143,500 \$ 191,300	
Total Savings (Deficit)	\$ (1,300) \$ 16,400		\$ 2,800 \$ 38,050		\$ 13,400 \$ 65,600	
Average Total Savings (Deficit) by Site	\$ (50) \$ 600		\$ (100) \$ 1,100		\$ 400 \$ 1,100	
PUBLIC SECTOR						
<u>Savings</u>						
● Annual Fuel Savings	\$ 16,750		\$ 15,250		\$ 49,650	
<u>Costs</u>						
● Capital Costs (1978\$)	\$ 87,900	\$ 116,450	\$ 134,250	\$ 179,400	\$ 242,350	\$ 322,550
● Financing in Year One (capital costs @ 5-3/4 % interest over 20 years)	\$ 9,450	\$ 12,500	\$ 14,450	\$ 19,300	\$ 26,050	\$ 34,700
● Depreciation (capital costs over 25 years)	\$ 3,500	\$ 4,650	\$ 5,350	\$ 7,200	\$ 9,700	\$ 12,900
● Total Annual Costs	\$ 12,950 \$ 17,150		\$ 19,800 \$ 26,400		\$ 35,750 \$ 47,600	
Total Savings (Deficit)	\$ 3,800 \$ 400		\$ (4,550) \$ 11,250		\$ 13,900 \$ 22,050	
Average Total Savings (Deficit) by Site	\$ 300 \$ 50		\$ (400) \$ 950		\$ 1,150 \$ 1,100	
PUBLIC AND PRIVATE SECTORS						
<u>Average Total Savings (Deficit) by Site</u>						
o At 15 percent Annual Fuel Savings	\$ 100 \$ (450)		\$ (150) \$ (1,050)		\$ 600 \$ 1,100	
o At 10 percent Annual Fuel Savings	\$ (500) \$ (1,000)		\$ (1,000) \$ (1,900)		\$ (900) \$ 1,100	
o At 5 percent Annual Fuel Savings	\$ (1,000) \$ (1,600)		\$ (1,800) \$ (2,700)		\$ (2,400) \$ 1,100	

Note: Range of savings (deficit) reflects ranges in capital cost assumptions. The 15 percent fuel savings have been assumed in the analysis.

Source: Harbridge House, Inc. (1976).

Less than 25 Million BTU/Hour	25 through 50 Million BTU/Hour	50 through 100 Million BTU/Hour	Total for All Size Categories
\$156,900	\$122,650	\$40,100	\$467,200
High	Low High	Low High	Low High
\$648,450	\$233,700 \$311,500	\$148,650 \$198,300	\$1,383,000 \$1,844,400
\$165,350	\$59,600 \$79,450	\$37,900 \$50,550	\$352,650 \$470,300
\$25,950	\$9,350 \$12,450	\$5,950 \$7,950	\$55,300 \$73,800
\$143,500 \$191,300	\$68,950 \$91,900	\$43,850 \$58,500	\$407,950 \$544,100
\$13,400 \$(34,400)	\$53,700 \$30,750	\$(3,750) \$(18,400)	\$59,250 \$(76,900)
\$400 \$(1,050)	\$5,950 \$3,400	\$(950) \$(4,600)	\$550 \$(700)
\$49,650	\$29,050		\$110,700
\$342,550	\$94,450 \$125,450	No Public Facilities in This Site Category	\$558,950 \$743,850
\$34,700	\$10,150 \$13,500		\$60,100 \$80,000
\$12,900	\$3,800 \$5,000		\$22,350 \$29,750
\$35,750 \$47,600	\$13,950 \$18,500		\$82,450 \$109,750
\$13,900 \$2,050	\$15,100 \$10,550		\$28,250 \$950
\$1,150 \$150	\$3,800 \$2,650		\$700 \$50
\$600 \$(700)	\$5,300 \$3,200	\$(950) \$(4,600)	\$600 \$500
\$(900) \$(2,200)	\$1,400 \$(700)	\$(4,300) \$(7,950)	\$(700) \$(1,800)
\$(2,400) \$(3,700)	\$(2,500) \$(4,600)	\$(7,600) \$(11,300)	\$(2,000) \$(3,100)

Analysis.

Because of these longer payback periods, the issue of data base discrepancies becomes important. Sections A and B have introduced two factors which indicate substantial overcapacity in the Worcester inventory. These are: (1) the tendency of manufacturers in the past to install systems with more capacity than required and (2) the existence of stand-by units which may not be subject to replacement.¹ Since capacity determines capital cost requirements for burner replacement while use determines fuel cost savings, overcapacity in the data base can result in estimates of substantially longer payback periods than would likely occur.

Exhibit II-5 illustrates the relationship between capacity and fuel use for the public and private sectors in the 6 through 10 million BTU per hour size category. Also shown is a line of constant slope which represents a rule of thumb for relating capacity to fuel use for normal heating requirements.² Underutilization in the public sector as compared with the private sector is evident in this size category. Moreover, the tendency for underutilization in the public sector in all size categories is indicated by the relationship of fuel savings to capital costs, which ranges from 9 to 12 percent in public facilities and from 19 to 26 percent in most private sector size categories. (One private sector size category -- 25 through 50 million BTU per hour -- has a ratio of 40 percent savings to costs.)

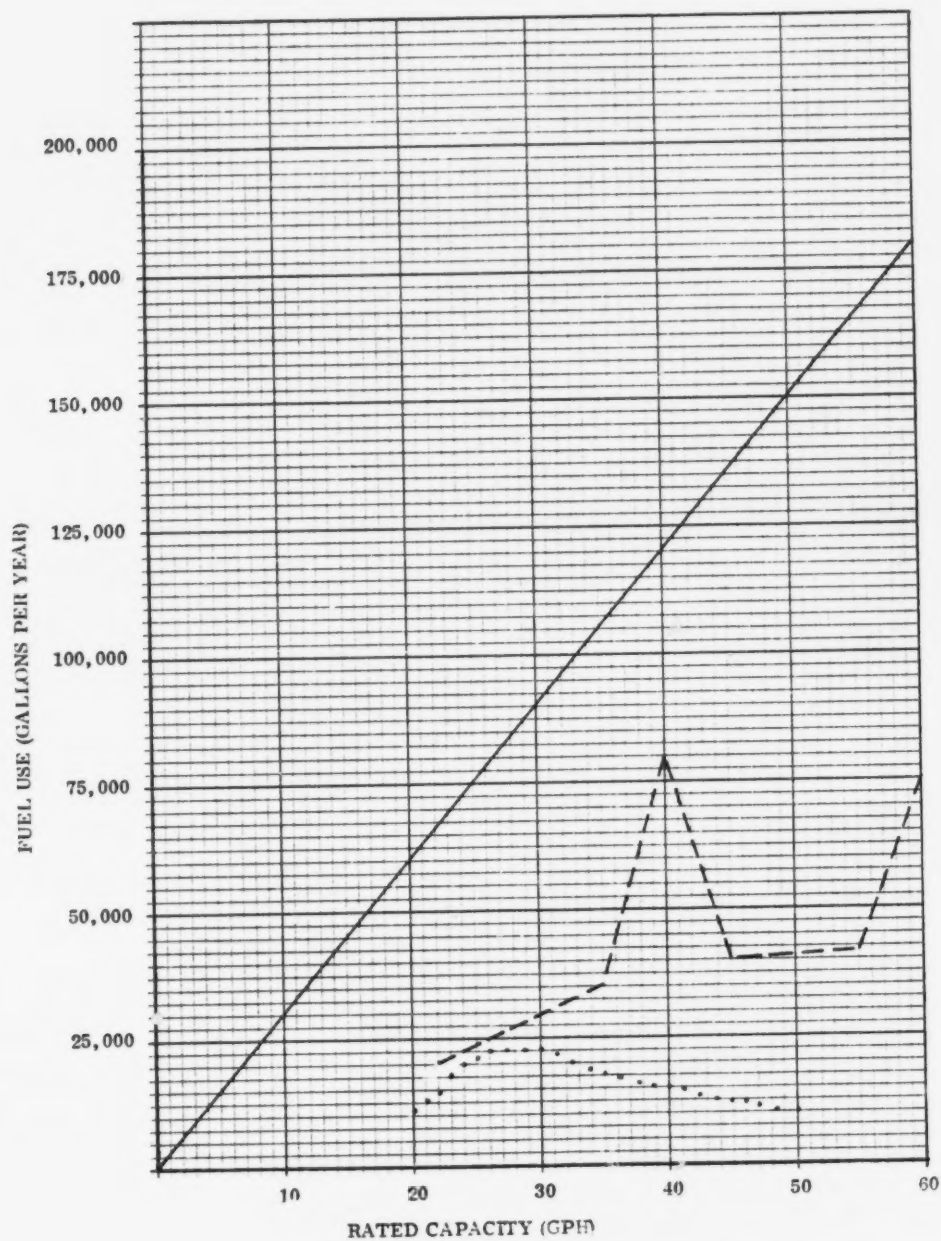
The second approach utilized in this cost analysis is illustrated in Exhibit II-4. As shown, the yearly breakdown of costs and savings are assessed for each sector to yield the net annual costs (deficit savings) or savings. Based upon a range of total capital costs for equipment (in 1978 dollars), annual principal and interest payments are calculated along with a yearly depreciation value based upon the assumptions discussed in Section B. These costs are then weighed against the total yearly fuel savings to arrive at the net annual range of costs or savings for each size category. Further breakdown by the number of sites affected within each size category allows an assessment of average individual owner costs or savings by year.

¹ DEQE intends to provide a mechanism whereby stand-by units may be exempted from the retrofit requirement.

² Mr. Roland Schmidt, Maryland Bureau of Air Quality and Noise Control. Telephone interview, 22 April 1976.

EXHIBIT II-5

RELATIONSHIP OF AVERAGE RESIDUAL FUEL USE
AND MARGINAL BURNER CAPACITY IN WORCESTER INVENTORY
6 THROUGH 10 MILLION BTU PER HOUR



..... Public Sector Burners.
 - - - Private Sector Burners.
 — Constant Relationship at 3000 hours of use per year.

Note: Individual points are connected for visual clarity only.

The analysis shows that for the constant annual fuel savings in each sector, annual financing costs and depreciation present a mixed picture in terms of net annual savings estimates. That is, the high range of costs often results in a net annual deficit, while savings may be experienced in the first year at the low cost estimates. In the private sector, a deficit is estimated in the size categories from 3 to 6 million through 10 million BTU's, as well as in the 50 through 100 million BTU category. Significantly, these yearly deficits, when broken down by the number of sites affected, show typical net annual costs per facility to range from \$50 to \$1,000. The one exception is in the largest site size category where annual costs per facility could reach \$4600. Because of the five-year term of financing assumed in the private sector, after the fifth year, all those facilities will experience a net annual savings equal to fuel cost savings minus depreciation. Moreover, it should be pointed out that savings are shown in several private sector categories, most notably in the 25 through 50 million BTU per hour grouping, where total user savings range between over \$50,000 to over \$30,000 with comparable individual facility savings in the range of about \$6,000 to \$3,500 per site.

In the results for the public facilities, savings are much more pronounced and widespread across all the size categories. Only one group, the 6 through 10 million BTU category has a net deficit for both the low and high estimates in the first year and even then, the net deficit per site only ranges from about \$400 to \$900. Moreover, because of the financing structure assumed for the public sector (see Section B), net costs in subsequent years will slowly decrease. The net savings experienced in other size categories in the first year (ranging from \$300 to nearly \$4,000 per site) will similarly increase slowly over the twenty-year term until only depreciation reduces the annual fuel cost savings.

In summary, then, payback periods in the private sector range from two to six years, with only one size category (the 25 through 50 million BTU per hour group) clearly experiencing a net annual savings from the start of replacement

burner operation. Public sector payback periods range from a low of five years to a high of 19 years, with the majority of the size categories recovering their investment within ten years. Net annual savings ranging as high as \$4,000 per site are potentially experienced by all public facility groups in the first year of implementation except for the 6 through 10 million BTU size category where an (annually decreasing) net deficit less than \$1,000 per site may be incurred.

A summary of the estimated net annual cost or savings in the first year of implementation of the marginal burner retrofit strategy is shown in Exhibit II-6. As indicated, the total costs or savings for public and private facilities in all size categories, range from a net annual savings of \$87,500 to a net annual cost of \$75,900. Because of the financing assumptions used in the analysis, net savings will gradually increase and net costs will gradually decrease in subsequent years. Moreover, the possibility of underutilization in both the public and private sectors (as previously described with regard to public facilities) indicates that these estimates may overstate the annual costs and understate the annual savings of strategy implementation.

III. FUEL TYPE CONVERSION STRATEGY

A. Background and Approach

The Massachusetts DEQE has proposed an air quality control strategy for particulates which focuses on several alternative changes in the type and characteristics of fuel oil burned within the Worcester City limits. Although fuel oil type changes are usually associated with sulfur oxide control strategies, recent evidence has indicated that particulate emissions during combustion are linked to viscosity and other characteristics of the oil burned, such as sulfur content. A variety of alternative fuel conversions has been proposed for evaluation with the purpose of assessing their relative cost effectiveness in particulate control. Harbridge House has evaluated the economic costs of the conversions, and DEQE is assessing the particulate emission reduction associated with each fuel oil type change.

The fuel type conversions evaluated are:

- Sources burning #6 (one percent sulfur) oil convert to #6 (0.5 percent sulfur) oil.
- Sources burning #6 oil convert to #4 oil.
- Sources burning #6 oil convert to #2 oil. (Facilities less than 50 million BTU per hour only.)
- Sources burning #4 oil convert to #2 oil. (Facilities less than 50 million BTU per hour only.)

Currently, Massachusetts requires that the sulfur content of fuel burned in Worcester not exceed one (1) percent. Although some sources may be burning fuel with less than one (1) percent sulfur content, specific data in this regard was not available to the study team. Consequently, in this analysis, fuel costs for #6 (one percent sulfur) have been applied to all sources currently burning #6. The few sources in the Worcester inventory which burn #5 have been grouped with sources burning #4 fuel oil, as directed by DEQE.

Each of the above conversions has been assessed according to two assumptions. First, the costs were evaluated assuming that the marginal burner strategy discussed

in Chapter II had not been implemented prior to the fuel conversions. Under this assumption, conversion of sources to #2 fuel oil (distillate) requires replacement of marginal burners, defined as natural draft rotary cup burners. (Chapter II, Section A, discusses the problems in burning distillate in natural draft rotary cups.) Under the second assumption, the costs were assessed under the condition of prior implementation of the marginal burner replacement strategy. Use of these two assumptions was based on DEQE's need for flexibility in evaluating strategy effectiveness.

Under the assumption of prior retrofit of marginal burners, the fuel conversion strategy would not be implemented until the effective date of the proposed retrofit regulation, or 1978. In order to provide a consistent comparison between the two analyses of fuel type conversions (with and without prior retrofit), it has further been assumed that even without prior implementation of the marginal burner retrofit strategy, the fuel conversion strategy will not be implemented until 1978.

1. Types of Costs Considered

The types of costs which have been assessed are shown in Exhibit III-1. As indicated, increased efficiency in the use of fuel is considered only when natural draft rotary cup burners have been replaced. In conversion of other types of burners from residual to distillate firing, efficient operation of the units was assumed prior to and after the conversion. (This is consistent with the Chapter II definition of marginal burners as natural draft rotary cup burners.) Moreover, based on discussions with DEQE, it was assumed that no change in maintenance practices or other (non-fuel) operating costs would result from any of the fuel type conversions evaluated.

As indicated in Exhibit III-1, capital costs as well as annual operating costs are associated with conversions from #6 and #4 oils (residual) to #2 oil (distillate). Since capital itself has a cost -- either an opportunity cost or financing cost -- several assumptions regarding the provision of capital for the conversions were required (see Section B). Moreover, different assumptions were used in evaluation of the costs of capital to private concerns as opposed to public sector facilities. The wide variations which can occur within each of these two categories (public and private) were not addressed in the quantitative analysis; however, a generalized discussion of financing options is included in Chapter I.

EXHIBIT III-1
TYPES OF COST CHANGES CONSIDERED IN
FUEL CONVERSION STRATEGY EVALUATION

<u>Assuming Marginal Burner Strategy Not Implemented</u>	<u>Assuming Marginal Burner Strategy Implemented</u>
• Combustion system modification to convert from #6 and #4 to #2 oil. • Replacement of marginal burners to convert from #6 and #4 to #2 oil. • Adjustment in quantity of fuel burned for sources requiring replacement of marginal burners to convert to #2 oil. • Adjustment in quantity of fuel burned resulting from differences in BTU content. • Adjustment in quantity of fuel burned resulting from preheating requirements for #6 and #4, but not for #2 oil. • Differential fuel prices.	• Combustion system modification to convert from #6 and #4 to #2 oil. • Adjustment in quantity of fuel burned for all sources retrofitted¹ under marginal burner strategy. • Adjustment in quantity of fuel burned resulting from differences in BTU content. • Adjustment in quantity of fuel burned resulting from preheating requirements for #6 and #4, but not for #2 oil. • Differential fuel prices.

¹ This fuel use savings is not attributed to the fuel conversion strategy under the retrofit assumption, but instead is represented in the data base.

Source: Harbridge House, Inc. (1976).

Costs associated with depreciation of capital equipment were also assumed to be incurred, based on the consideration that owners put aside enough capital each year to replace the equipment at the end of its useful life. It is recognized, however, that depreciation of equipment can provide significant tax advantages to owners. Under such circumstances (not quantitatively addressed in this study) depreciation may represent a net benefit of new equipment purchases.

Finally, it should be noted that the issue of availability of fuel oil by type has not been addressed in this analysis.

2. Worcester Combustion Source Inventory

The Worcester inventory of combustion sources provided data for specification of the characteristics of sources subject to fuel type conversions. The inventory data shows for each site: the number and type of burners; the type of boiler and burner controls; the rated capacity in million BTU per hour and in gallons per hour; and the fuel use and type. Since DEQE anticipates implementing a fuel type conversion strategy on the basis of the total rated capacities of all combustion units at a site, manipulation of data in the source inventory retained the following site-size categories: 3 to 6 million BTU's per hour; 6 through 10 million BTU's per hour; 10 through 25 million BTU's per hour; 25 through 50 million BTU's per hour; 50 through 100 million BTU's per hour; and over 100 million BTU's per hour. Despite this aggregation in presentation of results, however, certain costs, such as the combustion system modification costs for conversion from residual to distillate firing, were found to be a function of individual unit capacity (rather than total site capacity) and were accordingly evaluated on a burner-by-burner basis.

A summary of residual oil users in the Worcester inventory by size category and fuel type is shown in Exhibit III-2. As shown, 60 percent of the #6 oil is used by only 10 percent of the facilities -- in the greater than 100 million BTU per hour category. The #4 oil is used primarily in the site-size categories from 6 through 25 million BTU per hour, which account for 70 percent of its use and 70 percent of the facilities using it. Marginal burners, which are important to subsequent analysis because of the need to replace them in conversions from residual to distillate firing (if not already done so with prior implementation of the Chapter II strategy), are concentrated in the smaller site-size categories. Of the #6 oil users, 65 percent of the

EXHIBIT III-2
SUMMARY OF RESIDUAL OIL USERS IN WORCESTER

Site Size Categories -- Ownership	Sites				Total Burners				Marginal Burners				Total Fuel Use				Marginal Burner Fuel Use			
	#6		#4		#6		#4		#6		#4		#6		#4		#6		#4	
	Number	%	Number	%	Number	%	Number	%	Number	%	Number	%	(1000) Gallons	%	(1000) Gallons	%	(1000) Gallons	%	(1000) Gallons	%
Less than 6 Million BTU/Hour																				
-- Public	0		8		0		10		0		10		0		249.6		0		249.6	
-- Private	4	7%	9	22%	4	3%	9	14%	3	3%	9	18%	158.3	1%	406.0	2%	130.4	2%	406.0	13%
-- Total	4		17		4		19		3		19		158.3		655.6		130.4		655.6	
6 through 10 Million BTU/Hour																				
-- Public	0		10		0		19		0		21		0		302.3		0		302.3	
-- Private	10	17%	22	41%	15	11%	35	41%	13	15%	28	41%	589.2	2%	1574.0	8%	547.2	8%	1449.1	36%
-- Total	10		32		15		54		13		49		589.2		1876.3		547.2		1751.4	
10 through 25 Million BTU/Hour																				
-- Public	1		9		1		9		3		18		250.0		750.0		250.0		750.0	
-- Private	20	35%	13	29%	42	30%	36	34%	32	39%	24	35%	2862.9	11%	1713.8	38%	1806.8	38%	1100.5	39%
-- Total	21		22		43		45		35		42		3112.9		2463.8		2056.8		1910.5	
25 through 50 Million BTU/Hour																				
-- Public	1		3		2		7		2		7		104.1		421.0		104.1		421.0	
-- Private	10	19%	3	8%	29	22%	7	11%	21	26%	2	8%	4418.1	15%	579.9	18%	2287.8	37%	182.7	12%
-- Total	11		6		31		14		23		9		4522.2		1000.9		2391.9		603.7	
50 through 100 Million BTU/Hour																				
-- Public	3		0		7		0		0		0		1574.0		0		0		0	
-- Private	4	12%	0	--	19	18%	0	--	15	17%	0	--	1522.0	11%	0	--	965.5	15%	0	--
-- Total	7		0		26		0		15		0		3096.0		0		965.5		0	
Greater than 100 Million BTU/Hour																				
-- Public	2		0		4		0		0		0		3160.8		0		0		0	
-- Private	4	10%	0	--	19	16%	0	--	0	--	0	--	13,887.9	60%	0	--	0	--	0	--
-- Total	6		0		23		0		0		0		17,048.7		0		0		0	
All Site Categories																				
-- Public	7		30		14		45		3		45		5088.9		1722.9		354.1		1722.9	
-- Private	52	100%	47	100%	128	100%	87	100%	86	100%	74	100%	23,438.4	100%	3866.7	100%	6144.8	100%	3198.3	100%
-- Total	59		77		142		132		89		119		28,527.3		5589.6		6498.9		4921.2	

Source: Harbridge House, Inc. (1976). Based on DEXE's inventory of residual fuel oil users in Worcester.

marginal burners are in the 10 through 50 million BTU per hour categories, which also account for 75 percent of the marginal burner (#6) fuel use. The 6 through 25 million BTU per hour size categories include about 75 percent of the #4 oil-fired marginal burners and an equal percentage of #4 oil use in marginal burners. As may be expected, very little #6 fuel oil is used in the 10 million BTU per hour and under categories and no #4 oil is used in the greater than 50 million BTU per hour categories.

The breakdown of fuel users by public and private ownership is important to subsequent analysis because of the different financing options available to the two kinds of facilities. Roughly 10 percent of the total number of burners fired by #6 oil are estimated to be public facilities, while nearly 35 percent of the burners fired by #4 oil are estimated to be publicly owned. It is also noteworthy that the only publicly owned burners in the 50 million BTU per hour and under categories are classified as marginal burners.

One other aspect of the Worcester inventory of residual fuel users is important to subsequent analysis: the capacities of individual burner units. This consideration is important because the costs of system modification and/or burner replacement in the conversions from residual to distillate firing are a function of the individual unit capacity. In manipulating the data in the Worcester inventory, however, it became apparent that the rated capacity (in gallons-per-hour or in million BTU per hour) was often substantially greater than required by the fuel use totals, even after taking seasonal loadings into account. In more recently installed units, this apparent overcapacity may be attributable to stand-by units; in older facilities, however, the actual design specifications used 10 and 20 years ago provided for substantial excess capacity. Manufacturers interviewed noted that replacement of these older units often involves an (economical) reduction in the rated capacity with no loss in reliability or service. As a result of these considerations, the capital cost figures as applied to the inventory in Section C probably overstate total costs, particularly in the replacement of marginal burners.

B. Costing Procedures

The types of cost changes specified in Exhibit III-1 as well as the costs of capital and depreciation are described below with respect to sources of information and specific assumptions used in subsequent analysis.

1. Combustion System Modifications

Combustion system modifications are required for all sources in the conversion from residual to distillate firing. Specifically, replacement of pumps, relief valves, and strainer baskets are likely to be required. In addition, storage tanks would have to be cleaned and burners would have to be adjusted. Based on discussions with combustion equipment manufacturers, a range of \$350 to \$750 (1978 dollars) was considered to be representative of the costs associated with these changes for a unit with a capacity of 50 to 60 gallons per hour (GPH) or about 9-10 million BTU per hour.

At DEQE's request, the manufacturer cost estimates were inflated at a rate of nine percent per year based on the average annual rate of wholesale price increases from 1969 to 1975 for heating equipment plus two percent to account for future contingencies.¹ The nine percent figure was considered reasonable in light of some recent electric utility construction price adjustment clauses (in Massachusetts) obtained from DEQE, that were based on rates in the vicinity of ten percent per year.

On the average, equipment manufacturers estimated that half of the modification costs would go for equipment and half would be required for installation. Clearly the range of costs is wide, with the high cost estimate representing more than twice the low cost estimate. This is largely due to the variation in the

¹ Percentage increase in wholesale prices for heating equipment as follows: 1969 to 1970, 4.9%; 1970 to 1971, 4.4%; 1971 to 1972, 2.3%; 1972 to 1973, 1.9%; 1973 to 1974, 5.9%; 1974 to 1975, 21.7%. Source: U. S. Department of Commerce, Bureau of Census. Statistical Abstract of the United States (1975).

costs of pump replacement on different units. Because the manufacturer estimates were based on actual modification experience in the New England area, it was considered appropriate to use this wide range.

Modification costs are a function of unit size. As shown in Exhibit III-3, however, the cost variation by size is relatively minimal. Installation costs remain relatively constant over the size ranges, while the cost of equipment increases slightly as unit size increases.

2. Replacement of Marginal Burners

Costs associated with replacement of marginal burners have been obtained from the Chapter II analysis for all sources using natural draft rotary cup burners and fired by residual oil (#6 and #4). These costs are only incurred in the conversions from residual to distillate firing and are only attributed to the fuel conversion cost assessment under the assumption that specified no prior implementation of the marginal burner strategy. When marginal burners require replacement, the costs of modification are also incurred, since burner replacement alone does not include pump replacement and other changes required for conversion from residual to distillate firing.

3. Increased Efficiency in Fuel Use

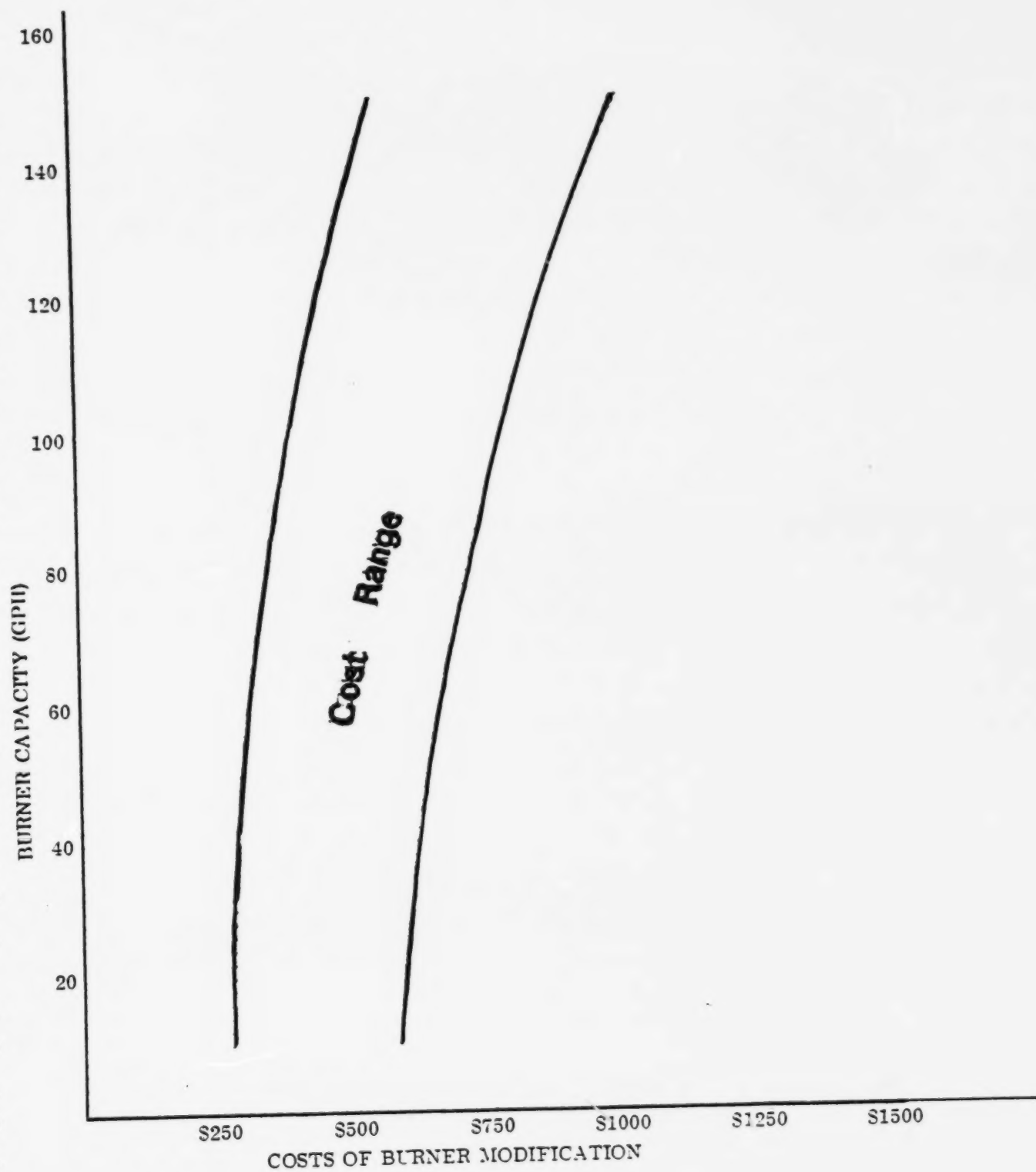
Increased efficiency in fuel use as a result of the fuel type conversions was determined to occur only when the costs of marginal burner retrofit are attributed to the fuel strategy, as previously described. As in Chapter II, the increased efficiency has been estimated at about 15 percent per year (assuming that normal maintenance includes one burner adjustment per year). These fuel cost savings are broken out separately in the analysis which is based on the assumption of no prior implementation of the marginal burner retrofit strategy. When prior implementation of the retrofit strategy is assumed, the fuel savings are incorporated prior to evaluation of the fuel conversion costs.

4. Adjustments for BTU Content

The differential BTU content of the fuel types was taken into account according to the following schedule:

EXHIBIT III-3

ESTIMATED COST OF COMBUSTION SYSTEM MODIFICATION



Source: Harbridge House Inc. (1976).

- #6 = 150,000 BTU per gallon
- #4 = 144,000 BTU per gallon
- #2 = 140,000 BTU per gallon

These heat content values were obtained from DEQE.

5. Adjustments for Residual Preheating

Conversion from residual to distillate firing obviates the need for preheating the fuel oil. It has been estimated that residual preheating fuel needs account for about three percent of the total fuel use.¹ In this analysis, the three percent figure has been used to represent fuel savings resulting from conversion to #2 oil from #6 oil and #4 oil.

6. Fuel Oil Prices

In conjunction with DEQE and Region I, EPA, it was determined that current fuel oil prices would be used in this economic assessment because of the extreme uncertainties in estimating future oil prices. Platts Oilgram, a daily publication, was used to obtain prices of the four types of fuel oil during the first four months of 1976 as shown in Exhibit III-4.² According to the Worcester Regional DEQE Office, fuel oil used in Worcester is transported via Boston Harbor. The middle range of the four-month average prices shown in Exhibit III-4 has been used in subsequent analysis.

¹ Walden Research Corporation. An Evaluation of Control Strategies for Stationary Fuel Burning Sources in the Thirty Inner Cities and Towns of the Metropolitan Boston Intrastate Air Quality Control Region, April 1973.

² A recent DEQE survey of 1976 fuel oil prices in Worcester indicated that the prices of #4 and #6 oil are subject to considerable variation as a result of discretionary discounts granted by distributors. Average prices based on several quotes for trailer loads were as follows: #6(1%S) \$.30 per gallon; #4(1%S) \$.32 per gallon; #2 \$.33 per gallon. Because of the minor differences between these average prices and those used in the analysis, no changes were made in the fuel price assumptions. It should be noted, however, that use of the prices shown in Exhibit III-4 (rather than the recently obtained DEQE quotes) yields more conservative results for both strategies.

EXHIBIT III-4
1976 FUEL OIL PRICES AT
BOSTON HARBOR, BY TYPE
(cents per gallon)

Month	Range of Prices Quoted				#2
	#6(1% <i>s</i>)	#6(0.5% <i>s</i>)	#4(1% <i>s</i>)		
January	26.9-27.0	27.8-28.1	27.6-30.1		30.6-32.2
February	27.9-28.0	29.6-29.7	29.0-30.1		31.1-32.7
March	27.9-28.0	29.6-29.7	29.0-30.1		31.6-32.7
April	27.9-28.0	29.6-29.7	29.0-30.1		30.6-32.7
Four Month Average	27.7-27.8	29.2-29.3	28.6-30.1		31.0-32.6
Middle Range	27.7	29.2	29.4		31.8

Source: Platt's Oilgram and Price Service. (McGraw Hill Publication) 5 January 1976, 5 February 1976, 4 March 1976, and 2 April 1976.

7. Cost of Capital

In this analysis, as in the Chapter II evaluation, the private sector has been assumed to borrow capital for five years at a ten percent rate of interest. (See Chapter II, Section 3.) Public sector financing has been assumed to be incorporated into a large bond issue, with a term of 20 years at a 5.75 percent interest rate. Because the objective of this analysis is to represent the annual average cost of strategy implementation, however, the public sector annual payments of principal and interest were averaged over the twenty-year period. (Actual payments would likely be large initially, and then decrease over time.)

8. Depreciation

As previously noted, depreciation has been considered in light of monies set aside annually for replacement of capital equipment at the end of its useful life. In this analysis, straight line depreciation has been utilized. Modification equipment has been assumed to have a life of ten years based on DEQE's estimate of the average remaining boiler life in Massachusetts. (Pumps must be replaced when boilers are replaced.) As in Chapter II, replacement burners were assumed to have a life of 25 years. At the end of its useful life, no scrap value has been attributed to the equipment.

C. Analysis and Results

The costing procedures were applied to the Worcester inventory of residual oil fuel users according to the specifications shown in Exhibit III-5. Using this methodology, the total costs and costs per site for each of the four conversions, broken down by site size category, are summarized in Exhibits III-6 and III-7.

Exhibit III-6, which shows the costs assuming prior implementation of the marginal burner retrofit strategy, indicates that the greatest costs in conversion from one type of residual to another type of residual oil will be borne by the larger size categories. In particular, the facilities in the greater than 100 million BTU per hour group will incur more than 60 percent of the total costs. This phenomenon is a clear reflection of the predominance of #6 residual fuel use in the larger size

EXHIBIT III-5
KEY FACTORS DETERMINING COSTS
OF ALTERNATIVE FUEL TYPE CONVERSIONS

With Prior Implementation of Marginal Burner Retrofit	With No Prior Implementation of Marginal Burner Retrofit
Conversion from #6 (1%) to #6 (0.5%)	
- Fuel Consumption Including 15% Savings for Marginal Burners (in gallons per year) - Prices of Fuel Types (in cents per gallon)	- Fuel Consumption (in gallons per year) - Prices of Fuel Types (in cents per gallon)
Conversion from #6 to #4	
- Fuel Consumption Including 15% Savings for Marginal Burners (in gallons per year) - Increased Fuel Use from 4% Differential in BTU Content (in gallons per year) - Prices of Fuel Types (in cents per gallon)	- Fuel Consumption (in gallons per year) - Increased Fuel Use from 4% Differential in BTU Content (in gallons per year) - Prices of Fuel Types (in cents per gallon)
Conversion from #6 to #2	
- Fuel Consumption Including 15% Savings for Marginal Burners (in gallons per year) - Increased Fuel Use from 7% Differential in BTU Content (in gallons per year) - Decreased Fuel Use from Elimination of Preheating Needs (in gallons per year) - Prices of Fuel Types (in cents per gallon) - Capital Costs of Modification Including Interest Charges (in dollars per year) - Depreciation Charge for Modification (in dollars per year)	- Fuel Consumption (in gallons per year) - Increased Fuel Use from 7% Differential in BTU Content (in gallons per year) - Decreased Fuel Use from Elimination of Preheating Needs (in gallons per year) - Decreased Fuel Use from 15% Savings in Marginal Burners (in gallons per year) - Prices of Fuel Types (in cents per gallon) - Capital Costs of Modification Including Interest Charges (in dollars per year) - Depreciation Charge for Modification (in dollars per year) - Capital Costs of Marginal Burner Retrofit Including Interest Charges (in dollars per year) - Depreciation Charge for Retrofit (in dollars per year)
Conversion from #4 to #2	
- Fuel Consumption Including 15% Savings for Marginal Burners (in gallons per year) - Increased Fuel Use from 3% Differential in BTU Content (in gallons per year) - Decreased Fuel Use from Elimination of Preheating Needs (in gallons per year) - Prices of Fuel Types (in cents per gallon) - Capital Costs of Modification Including Interest Charges (in dollars per year) - Depreciation Charges for Modification (in dollars per year)	- Fuel Consumption (in gallons per year) - Increased Fuel Use from 3% Differential in BTU Content (in gallons per year) - Decreased Fuel Use from Elimination of Preheating Needs (in gallons per year) - Decreased Fuel Use from 15% Savings in Marginal Burners (in gallons per year) - Capital Costs of Modification Including Interest Charges (in dollars per year) - Depreciation Charges for Modification (in dollars per year) - Capital Costs of Marginal Burner Retrofit Including Interest Charges (in dollars per year) - Depreciation Charges for Retrofit (in dollars per year)

Source: Harbridge House, Inc. (1976)

EXHIBIT III-6
ESTIMATED TOTAL ANNUAL COST AND ANNUAL COST PER SITE OF ALTERNATE FUEL OIL TYPE CONVERSION
ASSUMING PRIOR IMPLEMENTATION OF MARGINAL BURNER RETROFIT STRATEGY

Size Categories	Fuel Oil Type Conversions			
	#6 (1 1/2%) to #6 (0.5%)	#6 to #4	#6 to #2 ^A	#4 to #2 ^A
• 3 to 6 Million BTU per hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 2,100 (0.5%) \$ 500	\$ 4,000 (0.5%) \$ 1,000	\$ 7,900 - \$ 8,400 (2%) \$ 2,000 - \$ 2,100	\$ 15,000 - \$16,600 (12%) \$ 900 - \$ 1,000
• 6 Through 10 Million BTU per hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 7,600 (1.8%) \$ 800	\$ 14,600 (1.8%) \$ 1,500	\$ 30,700 - \$ 34,400 (7%) \$ 3,100 - \$ 3,400	\$ 42,300 - \$46,000 (33%) \$ 1,300 - \$ 1,400
• 10 Through 25 Million BTU per hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 41,200 (10.0%) \$ 2,000	\$ 78,900 (10.0%) \$ 3,800	\$152,880 - \$158,700 (37%) \$ 7,300 - \$ 7,600	\$ 47,000 - \$51,900 (37%) \$ 2,100 - \$ 2,400
• 25 Through 50 Million BTU per hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 62,500 (15.1%) \$ 5,700	\$119,700 (15.1%) \$ 10,900	\$227,800 - \$232,200 (54%) \$ 20,700 - \$ 21,100	\$ 23,400 - \$25,000 (18%) \$ 3,900 - \$ 4,200
• 50 Through 100 Million BTU per hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 44,300 (10.7%) \$ 6,300	\$ 81,900 (10.7%) \$ 12,100	N/A N/A	N/A N/A
• Greater Than 100 Million BTU per hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$255,700 (61.9%) \$ 42,600	\$490,300 (61.9%) \$ 81,700	N/A N/A	N/A N/A
• All Size Categories --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$413,400 (100.0%) \$ 7,000	\$792,400 (100.0%) \$ 13,400	\$419,200 - \$433,700 (100.0%) \$ 9,100 - \$ 9,400	\$127,700 - \$139,500 (100%) \$ 1,700 - \$ 1,800

^A Figures bracket most likely range. Because of capital cost financing assumptions costs shown are for the first five years of implementation and will be lower in subsequent years.

NA - Not Applicable.

Source: Harbridge House, Inc. (1976).

EXHIBIT III-7
ESTIMATED TOTAL ANNUAL COST AND COST PER SITE OF ALTERNATIVE FUEL OIL TYPE CONVERSIONS
ASSUMING NO PRIOR IMPLEMENTATION OF MARGINAL BURNER RETROFIT STRATEGY

Site Size Categories	Fuel Oil Type Conversions				#4 to #2 ^A
	#6(1%) to #6(0.5%)	#6 to #4	#6 to #2 ^A	#4 to #2 ^A	
• 3 to 6 Million BTU per Hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 2,400 (0.6%) \$ 600	\$ 4,600 (0.6%) \$ 1,200	\$ 8,300 - \$ 10,600 (2%) \$ 2,100 - \$ 2,700	\$15,900 - \$ 27,400 (16%) \$ 900 - \$ 1,600	
• 6 Through 10 Million BTU per Hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 8,800 (2.1%) \$ 900	\$ 16,900 (2.1%) \$ 1,700	\$ 35,500 - \$ 47,800 (10%) \$ 3,600 - \$ 4,800	\$36,100 - \$ 66,200 (39%) \$ 1,100 - \$ 2,100	
• 10 Through 25 Million BTU per Hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 46,700 (10.9%) \$ 2,200	\$ 89,500 (10.9%) \$ 4,300	\$135,900 - \$168,900 (38%) \$ 6,500 - \$ 8,000	\$32,300 - \$ 60,300 (34%) \$ 1,500 - \$ 2,700	
• 25 Through 50 Million BTU per Hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 67,800 (15.8%) \$ 6,200	\$130,100 (15.8%) \$ 11,800	\$186,000 - \$209,400 (50%) \$ 16,900 - \$ 19,000	\$32,300 - \$ 60,300 (11%) \$ 2,000 - \$ 3,000	
• 50 Through 100 Million BTU per Hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$ 46,400 (10.8%) \$ 6,600	\$ 89,000 (10.8%) \$ 12,700	N/A N/A	N/A N/A	
• Greater Than 100 Million BTU per Hour --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$255,700 (50.8%) \$ 42,600	\$490,300 (50.8%) \$ 81,700	N/A N/A	N/A N/A	
• All Size Categories --Total Annual Cost (percent of total, all sizes) --Annual Cost per Site	\$427,800 (100.0%) \$ 7,300	\$820,400 (100.0%) \$ 13,900	\$365,700 - \$436,700 (100%) \$ 8,000 - \$ 9,500	\$96,000 - \$171,600 (100%) \$ 1,200 - \$ 2,200	

^A Figures bracket most likely range. Because of capital cost financing assumptions costs shown are for the first five years of implementation and will be lower in subsequent years.

NA Not Applicable.

Source: Harbridge House, Inc. (1976).

categories, particularly the greater than 100 million BTU category (which accounts for about 60 percent of the #6 oil used in the Worcester inventory). A similar progression in costs as size increases can be seen in Exhibit III-7, which is based on no prior implementation of the marginal burner retrofit strategy. Both with and without implementation of the marginal burner retrofit strategy, total annual costs for conversion from one percent sulfur #6 oil to one-half percent sulfur #6 oil are in the vicinity of \$410,000 to \$430,000, while average annual costs per site for all size categories are about \$7000 to \$7300 (the higher figures represent the assumption of no retrofit). In the conversion from #6 oil to #4 oil, total annual costs are in the range from \$790,000 to \$820,000, while average annual costs per site for all size categories are from \$13,400 to \$13,900 (the higher figures represent the assumption of no prior retrofit).

In evaluating the cost figures estimated for the conversion from residual to distillate firing, it is instructive to note the role of fuel costs in determining total costs. As shown in Exhibit III-8, fuel costs represent from 80 to 97 percent of total annual conversion costs based on the assumption that the marginal burner retrofit strategy has been implemented. The variation is accounted for by the interaction of components of the Worcester inventory with the cost specifications such as fuel use by type, the BTU content and price differentials in the two proposed conversions, and the number and capacity of units subject to the capital costs of modification.

A major difference in the role of fuel costs in determining total costs, however, is evident in comparing the figures for the alternative assumptions about implementation of the marginal burner retrofit strategy. Assuming no prior implementation of that strategy, fuel costs represent from 30 to 50 percent of total costs in the #6 to #2 oil conversion, and actually represent a 30 to 90 percent savings in the conversion from #4 oil to #2 oil. Variation by size category is largely related to the number of marginal burners and fuel used in each, by category. An important conclusion to be drawn from the fuel cost savings estimated

EXHIBIT III-8

PERCENTAGE OF FUEL COST
IN TOTAL COST OF CONVERSION
FROM RESIDUAL TO DISTILLATE FIRING

<u>SIZE CATEGORIES</u>	<u>With Prior Implementation of Marginal Burner Retrofit</u>		<u>With No Prior Implementation of Marginal Burner Retrofit</u>	
	<u>#6 to #2</u>	<u>#4 to #2</u>	<u>#6 to #2</u>	<u>#4 to #2</u>
3 to 6 Million BTU/hour	93%	85%	32%	(60%)
6 through 10 Million BTU/hour	84%	88%	23%	(75%)
10 through 25 Million BTU/hour	95%	87%	33%	(89%)
25 through 50 Million BTU/hour	97%	80%	53%	(32%)

() indicates a negative percentage.

Source: Harbridge House, Inc. 1976.

in the #4 to #2 conversion is that, upon full amortization of the capital costs of modification and retrofit, a net annual savings will be experienced by the facilities subject to conversion. For the 30 public sector facilities currently using #4 oil, full amortization will occur after 20 years. (Net savings may actually occur prior to full amortization for the public facilities because of the commonly used sliding scale of interest and principal payments which was not taken into account in this analysis. See Section B) The 47 private facilities currently using #4 oil will have fully amortized the capital costs after five years based on the assumptions of this analysis.

Looking at the cost figures in Exhibit III-6 in more detail, it can be concluded that, with prior implementation of the marginal burner retrofit strategy, total annual costs of the conversion from #6 to #2 oil range from \$420,000 to \$430,000, with the 10 through 50 million BTU per hour size categories bearing more than 90 percent of total costs. The average annual cost per site for all size categories ranges from \$9100 to \$9400 (for the first five years). Only the 25 through 50 million BTU category shows average annual costs per site significantly above (more than two times) the average for all size categories.

The total annual costs of conversion from #4 to #2 oil, shown in Exhibit III-6, with prior implementation of the marginal burner strategy, range from about \$130,000 to \$140,000, with the 6 through 25 million BTU size categories bearing about 80 percent of the costs. Average annual costs per site for the first five years (all size categories) are from \$1700 to \$1800. Both the 10 through 25 and the 25 through 50 million BTU categories show average annual costs per site greater than this average for all the size categories. The substantial cost differences in these two residual to distillate conversions, assuming implementation of the retrofit strategy, appear to be attributable to differences in original fuel use, fuel use adjustments for BTU content and preheating, and fuel prices.

In Exhibit III-7, it is evident that the conversion from #4 to #2 is also less costly than the #6 to #2 conversion when it is assumed that the marginal burner

retrofit strategy has not been implemented. In particular, the total annual cost of converting from #6 to #2 ranges from \$370,000 to \$440,000, while the #4 to #2 conversion costs range from a total of \$96,000 to about \$170,000. Again, the 10 through 50 million BTU categories bear the majority of total costs (88 percent) in the #6 to #2 conversion; while the 6 through 25 million BTU categories bear the majority of total costs (73 percent) in the #4 to #2 conversion. Average annual costs per site (first five years only) for all size categories in the #6 to #2 conversion range from \$8000 to \$9500, with only the 25 through 50 million BTU category exceeding (by more than two times) this overall average. In the #4 to #2 conversion, the average annual cost per site for the first five years in all size categories is from \$1200 to \$2200. Both the 10 through 25 and the 25 through 50 million BTU categories exceed this overall average. Again, it is pointed out that because of financing arrangements, costs will be lower in the sixth year after implementation in all subsequent years.

A summary of total annual costs for all size categories is shown in Exhibit III-9 for the four fuel type conversions. As indicated, the conversion from #6 to #4 oil is most costly, while the conversion from #4 to #2 oil is least costly under both assumptions regarding implementation of the marginal burner retrofit strategy.

EXHIBIT III-9
ESTIMATED TOTAL ANNUAL COSTS OF ALTERNATIVE
FUEL TYPE CONVERSIONS

	#6(1% ^a) to #6(0.5% ^a)	#6 to #4	#6 to #2 ^a	#4 to #2 ^a
Assuming Prior Implementation of Marginal Burner Retrofit Strategy	\$413,400	\$792,400	\$419,200 - \$433,700	\$127,700 - \$139,500
Assuming No Prior Implementation of Marginal Burner Retrofit Strategy	\$427,800	\$820,400	\$365,700 - \$436,700	\$ 96,000 - \$171,600

^a Figures bracket most likely range. Because of capital cost financing assumptions, costs shown are for the first five years of implementation and will be lower in subsequent years.

Source: Harbridge House, Inc. 1976. See Exhibits III-6 and III-7 for more detailed breakdowns.

APPENDIX A
SUMMARY OF THE MARYLAND EXPERIENCE
WITH A ROTARY CUP BURNER RETROFIT
REGULATION

A. The Regulations

Regulations regarding the use of rotary cup burners were made effective in the State of Maryland in August 1975. In more lightly developed areas of Maryland, the regulations prohibit construction of fuel burning equipment fitted with a rotary cup burner or replacement of a burner with a rotary cup burner.¹ The metropolitan areas of Baltimore and Washington are, in addition to the above prohibition, governed by the following regulation:²

A person shall not cause or permit the operation of a rotary cup burner on fuel burning equipment having a maximum furnace heat input specified in the following table after the corresponding dates indicated in the table:

<u>Maximum Furnace Heat Input</u> <u>Million BTU per Hour</u>	<u>Effective Date</u>
5.0 or less	July 1, 1976
5.0 - 13.0	July 1, 1977

One year before the effective date, a schedule for replacement shall be submitted to the Department, specifying the location of and date of completion of replacement for each affected burner.

This regulation specifically exempts fuel oil burning equipment which has been fitted with a dust collector or for which a dust collector contract has been let prior to July 1, 1974.

The Maryland regulations do not discriminate among different types of rotary cup burners. Their definition reads, "... a fuel oil burner which employs

¹ Maryland State Department of Health and Mental Hygiene. Regulations Governing the Control of Air Pollution in Area(s) I, II, V, VI. (As amended through June 17, 1975), page 15.

² Maryland State Department of Health and Mental Hygiene. Regulations Governing the Control of Air Pollution in Area(s) IV, V. (As amended through June 17, 1975), page 5.

a rotating cup to atomize and mix fuel oil with air for combustion."¹ Moreover, by not indicating a compliance date for replacement of rotary cup burners having a maximum furnace heat input greater than 13 million BTUs per hour, the retrofit requirement does not apply to those large facilities.

B. Motivation for and Objectives of Rotary Cup Burner Regulations

The primary objectives of the rotary cup burner regulations were (1) to reduce particulate emissions, and (2) to save energy by more efficient combustion. Moreover, the regulations were intended to accelerate an already apparent trend away from the use of rotary cup burners in small boilers. This trend is documented in Exhibit A-1 for the residual fired boilers in the Washington and Baltimore metropolitan areas. According to the background information prepared prior to promulgation of the regulations, the trend away from rotary cup burners resulted from voluntary action taken by industry to remedy complaints of service people regarding the critical adjustment necessary for good combustion and the tendency of the burners to get out of adjustment.²

The retrofit exemption for units having already installed dust collectors, was incorporated into the regulations because of the need to integrate the retrofit regulations with other air pollution control requirements. In particular, the regulations which mandated the phase-out of rotary cup burners also incorporated (as an unrelated provision) the elimination of a requirement for dust collectors on small boilers. Consequently, it appears that the exemption to rotary cup burner retrofit was included so as not to penalize those units which had voluntarily installed dust collectors prior to the deadline for that requirement.

The implicit exemption for units having a heat input greater than 13 million BTU was included for two reasons. First, rotary cup burners are typically found in small

¹ Maryland State Department of Health and Mental Hygiene. Regulations Governing the Control of Air Pollution in the State of Maryland. (As amended through June 17, 1975). page 4.

² Maryland State Department of Health and Mental Hygiene. Background Information for Proposed Changes in Maryland Regulations, April 1974, page 6.

EXHIBIT A-1
INSTALLATIONS OF ROTARY CUP BURNERS
IN RECENT YEARS
(Residual Oil Only)

Year	Number of Burners	
	Washington Metropolitan Area	Baltimore Metropolitan Area
1968	37	9
1969	32	8
1970	17	4
1971	2	1
1972	0	4
1973	0	0

Source: Maryland State Department of Health and Mental Hygiene.
Background Information for Proposed Changes in Maryland
Regulations, April 1974.

units because of the relative diseconomies associated with their use in larger size boilers. (Seventy-one percent of the rotary cups in the Baltimore and Washington metropolitan areas were less than 5 million BTU per hour and 97 percent were less than 15 million BTU per hour.¹) Secondly, the relatively few large units equipped with rotary cup burners were found to be used in processing operations, primarily food processing, such that greater care and maintenance of the burners was exercised in order to meet the processing specifications.²

C. Economic Impact Assessments

Three assessments of the economic costs associated with rotary cup burner replacements in Maryland have been completed. The first was done in 1974 prior to promulgation of the regulations and concluded that replacement of the 1820 rotary cup burners (in the Baltimore and Washington areas) falling in the 1 to 15 million BTU range would cost from \$8.6 to \$10.0 million dollars. As shown in Exhibit A-2, replacement equipment costs for burners with a heat input range from 6 to 15 million BTU were estimated at \$7000, while \$3000 was used as the cost for replacement units with heat input from 1 to 5 million BTU. Exhibit A-3 graphically presents the estimated costs, by size, for equipment to replace rotary cup burners.

In this first cost estimate developed by Maryland, the expenditure was regarded as being "paid back" within a period of about 15 months. Oil prices, at that time (1974), were assumed to be \$0.25 per gallon (residual), and a ten percent saving in the quantity of oil used was estimated to represent the typical burner efficiency differential. Investigations conducted to develop the ten percent savings figure, indicated that some manufacturers claimed energy savings as high as 25 percent and that the oil industry regarded the savings potential to be as high as 48 percent. The Maryland Bureau of Air Quality and Noise Control accepted the possibility of savings of 25 percent but used the ten percent figure in the belief that it represented a more average condition. Exhibit A-4 shows some instances where more spectacular savings were made.

¹ Background Information for Proposed Changes in Maryland Regulations, April 1974.

² F. Russ Summers, Bureau of Air Quality and Noise Control, Maryland State Department of Health and Mental Hygiene. Telephone interview 7 April 1976.

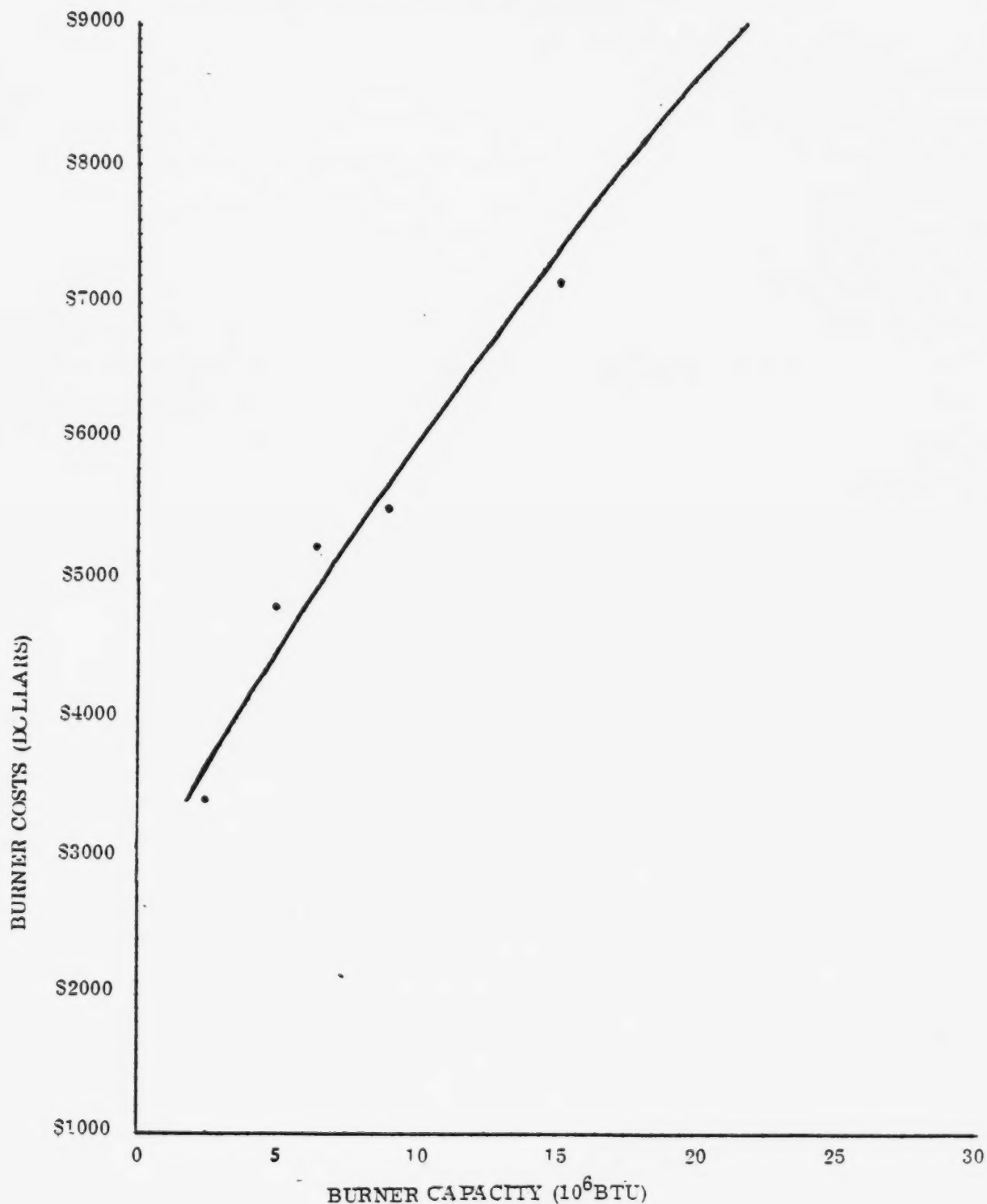
EXHIBIT A-2
ESTIMATED TOTAL COST OF REPLACING ROTARY CUP BURNERS
IN BALTIMORE AND WASHINGTON METROPOLITAN AREAS

<u>Burner Input Range</u>	<u>Equipment Costs</u>
<u>6-15 MBTU/hr.</u>	
Baltimore Area (269 @ \$7,000)	\$1,870,000
Washington Area (213 @ \$7,000)	<u>1,480,000</u>
	\$3,350,000
<u>1-5 MBTU/hr.</u>	
Baltimore Area (609 @ \$3,000)	\$1,820,000
Washington Area (727 @ \$3,000)	<u>2,180,000</u>
	\$4,000,000
Total Equipment Cost (Both Areas)	\$7,350,000
Estimated Installation Cost	<u>1,200,000</u>
Total Estimated Cost	\$8,550,000

Source: Background Information for Proposed Changes in Maryland Regulations,
April 1974.

EXHIBIT A-3

ESTIMATED COSTS OF OIL BURNER EQUIPMENT
TO REPLACE THE ROTARY CUP BURNER OF VARIOUS SIZES



Source: Maryland Department of Health and Mental Hygiene (1974).

EXHIBIT A-4

FUEL SAVINGS EFFECTED BY REPLACEMENT OF ROTARY CUP
RESIDUAL OIL BURNERS WITH MODERN AIR ATOMIZING UNITS

CONVERSION DATE	ANNUAL CONSUMP. FOR YR. BEFORE CONVER. (gals)	DEGREE DAYS FOR YR. BE- FORE CONVER.	CONSUMP. PER DEGREE DAY (gal/ D. day)	CONSUMP. FOR SAME PERIOD AFTER CONVER.	DEGREE DAYS FOR SAME PERIOD AFTER CONVER.	CONSUMPTION PER DEGREE DAY (gal/ D. day)	SAVINGS PERCENT
FEB 72	682,268	4196	162.6	488,255	3921	124.52	23.4
JUN 68	197,054	4227	46.62	161,056	4130	39.0	16.3
JUN 73	52,126	2820	18.48	44,175	2607	16.95	8.3
JUN 73	56,504	2820	20.04	44,176	2607	16.95	15.4
JUN 73	92,214	2820	32.7	67,680	2607	25.96	20.6
JUN 73	119,245	2820	42.29	85,299	2607	32.72	22.6
NOV 69	1,112,450	4332	256.79	749,669	3822	196.15	23.6

Number of
Burners

3

4

2

2

2

2

?

Source: Background Information for Proposed Changes in Maryland Regulations. April 1974.

AVERAGE PER BURNER = 21.3

The second economic impact assessment resulted in an estimated cost of about \$16,300,000 for replacement of rotary cup burners in the Baltimore and Washington areas. Data is not available to account for the substantial increase over the previous estimate, however, it may be attributable to inclusion of burners over 15 million BTU per hour input and/or to increased prices. In this assessment, it was noted that most of the rotary cups in the Baltimore and Washington areas were over five years old and would have to be replaced anyway within a relatively short time. Based on a ten percent savings in fuel consumed at a cost of \$0.33 per gallon, it was estimated that an average installation (costing \$7000) would pay for itself in about 13 months.

In both of these assessments of the payback period, it is important to recognize that Maryland did not use their actual fuel burner inventory for assessment of costs and savings. Instead, both costs and savings were based on a typical facility. Of particular relevance is their use of 3000 hours of operation per year as a factor to relate combustion unit capacity to fuel use. Engineers in the Bureau of Air Quality and Noise Control have noted that the figure of 3000 hours has been used in the heating equipment industry for relating capacity to fuel use. However, on request by Harbridge House, Maryland officials checked a few sources in their inventory and found some discrepancies between the 3000 hour per year assumption and actual fuel use (which was lower) (see Chapter II, Section C).

The third economic assessment was undertaken in February 1976 and consisted of a survey of cost figures which had been presented as bids for an actual rotary cup burner. Fifty-three cost figures (including all equipment and installation costs) were obtained from nine companies. The replacement cost figures were plotted versus burner input rating in million BTU per hour and divided into four categories according to the fuel burning capabilities of the replacement burner. As shown in Exhibit A-5 the results of the survey indicated a range of costs from \$2000 to \$12,000 per burner. Moreover, it was found that most Boards of Education have specified that school oil burner replacements be able to burn both residual and distillate oil in light of uncertain fuel supplies. This specification, according to the bid prices shown

ROTARY CUP REPLACEMENT COST

SYMBOL FUEL CAPABILITY

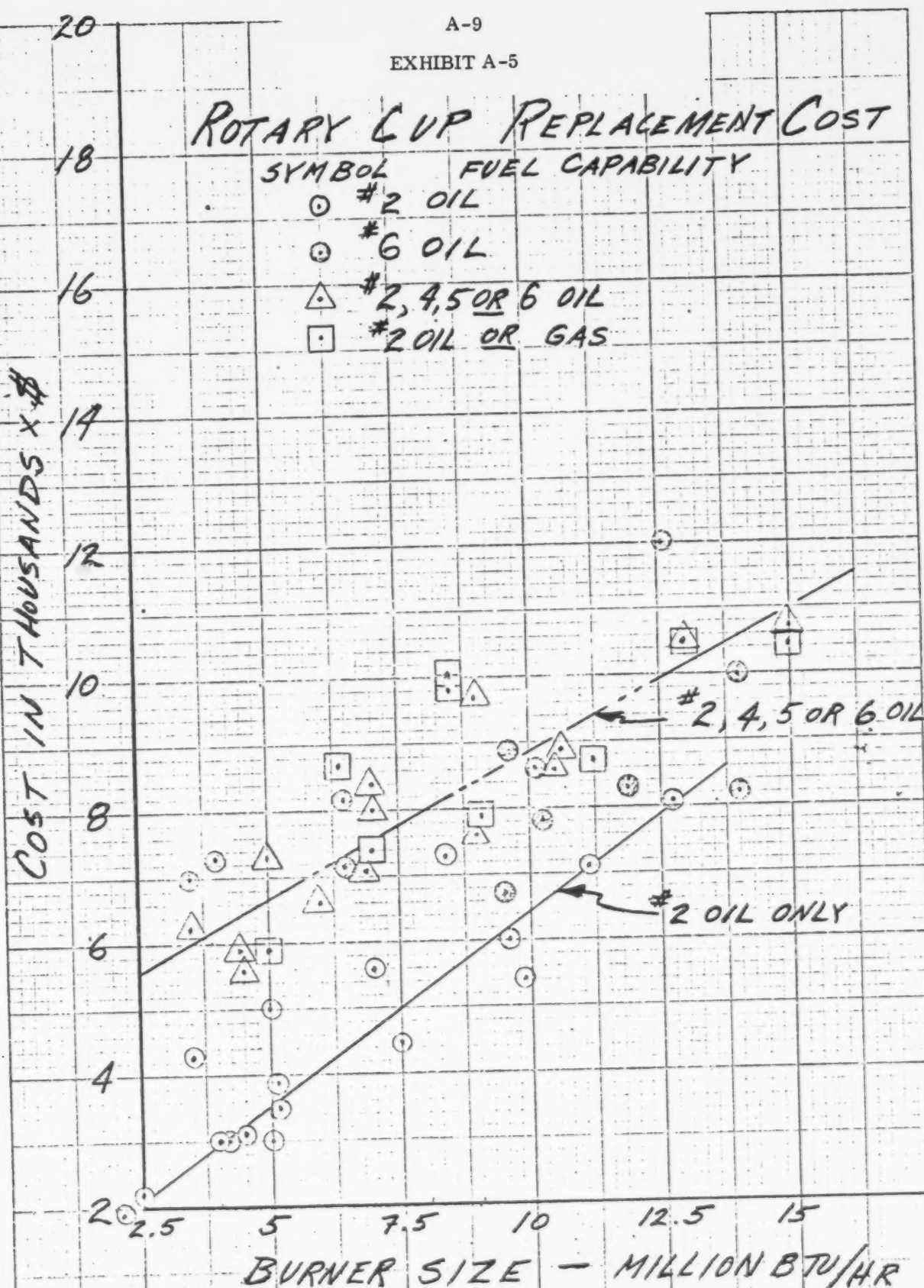
○ #2 OIL

⊙ #6 OIL

△ #2, 4, 5 OR 6 OIL

□ #2 OIL OR GAS

COST IN THOUSANDS X \$



SOURCE: STATE OF MARYLAND, DEPT. HEALTH AND MENTAL HYGIENE

2-2-76

in Exhibit A-5 may result in costs \$2000 to \$3000 greater than those associated with replacement of burners with single fuel oil type capability.

D. Issues Raised in Implementation

Based on its rotary cup burner inventory, Maryland notified affected parties of the retrofit requirement in writing, indicating the timing for submission of a compliance schedule and the motivation behind issuance of the regulations. In retrospect, individuals at the Bureau of Air Quality and Noise Control note that the potential for a positive return on investment (through increases in fuel use efficiency) were not stressed sufficiently in the initial notification thereby creating some needless friction in implementing the regulation.¹ Moreover, the wording of the regulation does not specify the components of a compliance schedule. This omission caused some owners of rotary cups to notify the Bureau that they would comply by the specified date, without making firm commitments for replacement equipment and installation.

Perhaps a greater problem relating to the initial stage of implementation, however, was the discovery on the part of the Bureau that their inventory, by burner type, was not accurate. Apparently, some owners of rotary cups lacked knowledge of alternative burner types when registering their facilities and mistakenly reported their burners as gun pressure or other types of burners rather than rotary cups. This has resulted in several owners receiving notification of the regulation only a few months prior to the date upon which the compliance schedule was required. In that short time period, they found they could not obtain estimates of burner replacement costs from three of the only eight or nine companies serving the Baltimore and Washington areas.

A similar timing problem was encountered as a result of a delay of ten months in getting the initial regulation published in the Maryland Register. In particular,

¹ Mr. Roland Schmidt, Division of Compliance, Bureau of Air Quality and Noise Control, Maryland State Department of Health and Mental Hygiene. Telephone interview 15 April 1976.

the regulation was supposed to become effective in October 1974, but publication delays resulted in its effective date of August 1975. Roland Schmidt at the Bureau indicated the need for a one-year period for owners to investigate costs and arrange for replacement.

In later stages of implementation, the issue of economic hardship has been in the forefront. Schools, in particular, have claimed that they cannot obtain budget allocations to meet the compliance deadlines. In one county, where 411 rotary cups are currently installed in school buildings, public officials estimated that it would take 17 years for them to comply with the regulation.¹ In another county, however, officials estimated that their 170 rotary cups in school buildings could be replaced over a two-year period.²

Other claims of economic hardship have come from private sector establishments which are currently operating on a marginal basis. Some owners of partially occupied buildings, for example, have said that they simply cannot comply with the regulation.

These claims of economic hardship are, as yet, unresolved in Maryland. The public hearing procedure, which is triggered when a facility refuses to sign a compliance plan, has not been started to date. So far, extra months and sometimes an extra year has been allowed for recalcitrant owners to consider replacements. (This allowance is also partially due to the previously mentioned timing problems.) Notifications of violations have also been issued to some facilities.

Another aspect of the compliance issue regards existing rotary cup burners which are planned to be phased out after the effective date of compliance. The regulation, as written, would require such burners to be replaced. It is expected that these situations will have to be resolved in the hearing process.

¹ Mr. Roland Schmidt. Telephone interview 15 April 1976.

² Ibid.